List of V0 Standards:

BAL-001-0 — Real Power Balancing Control Performance

Robert Coish - MAPP OS
Larry Larson – Otter Tail
No measures associated with Requirement 3.
No measures associated with Requirement 4.

Alan Boesch - NPPD
R3 and R4 - No measurements. Requirement 1 and 2 have measurements but 3 and 4 do not. Every requirement should be measureable or it should not be a requirement. Note this is typical of many standards. There are many cases of the standards having multiple requirements and only one measurement. I will only provide this comment once. I am sure you are familiar with all of the requirements that do not have measurements.

Dean Shiro – XCEL
Calculation for CPS1 should not include the character % after the number 100.

Deanna Phillips - BPA
M1 - To avoid the potential for "gaming", this Standard should include requirements and/or measurements, to ensure that the "sustained interruption" clause of this measure is used seldom enough to guarantee that the resultant CPM2 calculation is representative of the Balancing Authority's actual operation. If not covered in present NERC policy, then please pass this comment on to the appropriate Version 1 drafting teams.

Linda Campbell – FRCC
Recommend the following revision to remove the words "reporting area's ACE" : Normally, sixty (60) clock-minute averages of BALANCING AUTHORITY AREA'S ACE and of the respective Interconnection's frequency error will be used to compute the respective Hourly Average Compliance parameter.

Alan Boesch - NPPD
Compliance monitoring process - The statement on the reset period seems quite stringent. If you need to go a full calendar month without a violation (defined as a Violation clock-ten minute) it would be almost impossible to reset. A more reasonable reset would be be in compliance for a calendar month.

Dean Shiro – XCEL
Attachment 001-1: In the description for the variable V in the CPS2 Data table, Number of incidents per hour should be changed to per month. Same for description of variable U

BAL-002-0 — Disturbance Control Performance

Deanna Phillips – BPL - PBL
Though they are technically correct, the first two sentences of the first paragraph are located in the wrong section of this standard. Since they refer to which disturbances must be reported on for compliance purposes, they belong in the Compliance Monitoring Process section of this standard.

Alan Boesch - NPPD
R2 - The requirement should state a minimum performance level that must be met by the reserve levels and mix of Operating Reserve - Spinning and Operating Reserve - Supplemental.

Alan Boesch - NPPD
R3 - There appear to be two requirements here. First the requirement to deploy contingency reserves. Second the requirement to review the amount of reserves to be carried. They should be split. There is no measurement included for review of the contingencies on an annual basis and there should be.

Deanna Phillips – BPL - PBL
An important part of this requirement that is missing from what is written here is that the specified recovery MUST occur within the Disturbance Recovery Period; which is presently specified as 15 minutes. Rectify this by adding "within the Disturbance Recovery Period" to the end of the first sentence of this requirement.

Alan Boesch - NPPD
Reset Period - The reset period should be one calendar quarter without a violation on a reportable disturbance.

Linda Campbell – FRCC
The Levels of Non-compliance are not really levels of non-compliance. These are what a BA or RSG must do if they do not meet the DCS, so really appear to be sanctions or penalties associated with non-compliance. This should be reviewed and corrected.

BAL-003-0 — Frequency Response and Bias

Bill Dearing – Brant PUD
In reference to "NERC Operating Committee" throughout the Ver0 Standards, would it be more correct to use "Compliance Monitor?"

Deanna Phillips – BPA
R2 - Please revise scope of this requirement to include only those things pertaining specifically to the requirment to operate AGC on tie-line bias control. The remaining information on how the BA is to calculate its Frequency Bias setting, including that on fixed verses variable bias setting and how they should be calculated should be moved to Standard 003 R1, which is the specific requirement for calculation of Frequency Bias Obligation.

Eric Grant – Progress
Phil Creech – Progress
R6 - As a "Standard", the 90 minute rule for re-establishing contingency reserves should not be subject to arbitrary change by the NERC OC. This statement applies across the board to each standard represented in Version 0. In addition, many Reserve Sharing Groups have legally binding contracts in place that cannot easily be changed, resulting in noncompliance.

Guy Zito – NPCC
At a recent Resources Subcommittee meeting, the RS interpreted the second contingency rule to exclude off-line resources that were activated to provide contingency reserve. This was always the intent and the addition of a sentence to clarify this would be beneficial.

Brandian – ISO-NE (Guy Zito – NPCC)
The NERC Resources Subcommittee interpreted that the 1% minimum applies to the computations of Policy 1 Sections 2.1.1 and 2.1.2 [Standard 003, R2]. A specific sentence should be added to the end of R4 to define clearly its applicability. This is not a change in policy.

Brandian – ISO-NE (Guy Zito – NPCC)
When computing bias, “several disturbances” is vaguely defined.

Travis Bessier – TXU
The deletion of governor-related items (Policy 1.C) can contribute to decline on frequency response performance and potentially degrade reliability.

Martin Huang – BC Transmission
Standard is translated correctly. Utility with variable freq. bias may still misrepresent their freq. bias for a significant part of the year due to the requirement for "monthy average Freq. Bias Setting that is at least 1%" of yearly peak demand.

Deanna Phillips - BPL-PBL
The words "as close as practical to" are not sufficiently difinitive enough to enable this requirement to be measurable. Since existing policy does not give any further guidance in this area, we ask that this issue be forwarded to the appropriate Version 1 Drafting Team for resolution.

Al DiCaprio – MAAC
The measure is not connected to the requirements. The reqirements for Standard 3 all refer to Frequency Bias and Frequency Bias setting. The measure is to complete a Response Survey. A measure of Frequency Bias settings is to have a Bias setting. The fact that the requirement mandates a minimum setting (i.e a system with no response at all must have a FBS), makes the measurement of a system's response to an ad hoc event a meaningless exercise vis-à-vis the FBS.

BAL-004-0 — Time Error Correction

- No comments for V1

BAL-005-0 — Automatic Generation Control

Deanna Phillips – BPL-PBL
PURPOSE: To properly communicate the purpose of this complex standard to those who are unfamiliar with this subject, it is necessary to first discuss "what we are trying to accomplish" before stating "how we will to accomplish it through use of ACE and Regulating Reserves". This can be achieved by reverseing the order of the two sentences in this paragraph and rewording them such that they flow appropriately.

Deanna Phillips – BPL-PBL
Placing the requirements in this standard in the order that they appeared in the NERC Policies has resulted in them being in a confusing and seemingly random order. Calrity of this standard would be improved immensely if these many requirements were to be reordered in more of a building block approach; beginning with the most fundamental and working toward the most complex. A suggestion would be to put them in the order of R1, R6 - R8, R13 - R16, R9 - R12, R2, R3, R4, R5.

Deanna Phillips – BPL-PBL
The three sentences of this requirement are actually three separate requirements that will require separate measures for compliance. Therefore, we ask that they be split into two separate requirements.

Deanna Phillips – BPL-PBL
The phrase "shall sample data" is not specific enough about "what data" as to enable this requirement to be measurable. If possible, please list specifically what data or types of data are meant. If existing policy is not specific enough in this area to be able to do this as a part of Version 0 then, we ask that this issue be forwarded to the appropriate Version 1 Drafting Team for resolution.

Deanna Phillips – BPL-PBL
The two sentences of this requirement are actually two separate requirements that will require separate measures for compliance. Therefore, we ask that they be split into two separate requirements.

Deanna Phillips – BPL-PBL
The words "prevent such service from becoming a burden upon …" are not sufficiently difinitive enough to enable this requirement to be measurable. Since existing policy does not give any further guidance in this area, we ask that this issue be forwarded to the appropriate Version 1 Drafting Team for resolution.

Brandian – ISO-NE (Guy Zito – NPCC) (Pete Henderson – IMO)
Levels of Non-Compliance - These are missing and needs to be added in Standard simultaneously.

BAL-006-0 — Inadvertent Interchange

Deanna Phillips – BPA
R1-R5 These requirements correctly describe how to calculate Inadvertent Interchange. However, they fail to actually address the stated purposes of the standard, which are to ensure that both "reliability is not compromised by inadvertent flows" and "Balancing Authorities do not excessively depend upon (others) ". Please either modify the purpose to reflect the requirements or add requirements that address the purposes as stated.

Deanna Phillips – BPL-PBL
The two sentences of this requirement are actually two separate requirements that will require separate measures for compliance. Therefore, we ask that they be split into two separate requirements.

Ed Riley
CAISO
R4 - In the last paragraph, the term "non-reliability considerations" is going to be impossible to define in this context. After-the-fact changes that are made between consenting BAs do not affect the interconnection.

Peter Henderson – IMO (Guy Zito – NPCC CP9) (Chris de Graffenried and Ralph Rufrano – NYPA)
Remove the wording "with like values but opposite signs" in order to make more clarity in R4.

Alan Boesch – NPPD
Compliance Monitoring - The Compliance Monitoring Process contains requirements. The level of non-compliace refers to the requirements in the Compliance Monitoring Process instead of the requirements.

Deanna Phillips – BPL-PBL
The section 1G1.1 of the Compliance Monitoring Process talks specifically about a requirement for the BA to do AIEs to submit data to NERC for analysis purposes. Since AIE is not a part of the NERC Compliance Program at this time, this section should be moved to in the Requirements section of this standard.

Alan Boesch – NPPD
Levels of Non Compliance - The only non-compliance is related to providing a report and does not support the purpose “to ensure that, over the long term, the BALANCING AUTHORITY AREAS do not excessively depend on other BALANCING AUTHORITY AREAS in the INTERCONNECTION for meeting their demand or INTERCHANGE obligations.”

CIP-001-0 — Sabotage Reporting

Kenneth Goldsmith - Alliant
It is almost impossible for us to be aware of all acts of actual or potential sabotage that could affect multi-sites with in the larger portions of the interconnection. This should be reduced to each entity's area of ownership

Kenneth Goldsmith - Alliant
There is no definition of sabotage. Suggest using the following definition; Sabotage means a verifiable deliberate act that is directed against a company's facilities or their portions of the interconnection that could directly or indirectly endanger public health or the reliability of the system.

COM-001-0 — Telecommunications

Gerald Reahlt – Manitoba
There may be redundancy here with Policy 5A Requirement 1.

Robert Snow
R1 - In section R1, for all but the smallest areas, redundancy and diversely routed telecommunications is required.

Guy Zito – NPCC
R1 thru R5 - Add "Transmission Owners, Generator Owners, Generator Operators and Load Serving Entities" to the list of FM entities this applies to.

Ralph Rufrano – NYPA
NPCC's participating members recommend changing R1 to;
Each Reliability Authority, Transmission Operator, Balancing Authority, Transmission Owner, Generator Owner, Generator Operator and Load Serving Entity shall provide adequate and reliable telecommunications facilities internally and with others for the exchange of Interconnection and operating information necessary to maintain reliability. Where applicable, these facilities shall be redundant and diversely routed. -and changing R2 – R5 from "Each Reliability Authority, Transmission Operator, and Balancing Authority shall" To "Each Reliability Authority, Transmission Operator, Balancing Authority, Transmission Owner, Generator Owner, Generator Operator and Load Serving Entity shall" -Remove R6 and attachment 029-1 should be removed. Those procedures apply to NERCnet users, which is a small subset of community that R1 – R5 apply to. Also, these procedures are the steps for obtaining and using NERCnet. Those procedures should not be part of a Reliability Standard.

COM-002-0 — Communications and Coordination

Mike Kormos – PJM (PSE&G)
In Market environment voice communication with generators is not necessarily required

FRCC
R1 - Reliability Authority should be included in this requirement.

Ray Morella – FirstEnergy
R2 - All groups active in the industry should be required to report sabotage incidents and security breaches.

Brandian – ISO-NE (Guy Zito – NPCC)
R4 - Even though this is a direct translation of the existing Policy, NPCC requests a clarification of the repeat back requirements, specifically are they for emergency, abnormal, normal, all of the above, provide specific examples

EOP-001-0 — Emergency Operations Planning

Mike Kormos – PJM
Business activity

FRCC
R4 – R5 - We suggest combining the two requirements and reword for clarity.

Brandian – ISO-NE (Guy Zito – NPCC) (Pete Henderson – IMO)
R5 - Remove 1, 2, 3, 7, 8 and 9. NPCC recommends that the fuel related guides are not considered for translation into requirements.

Linda Campbell – FRCC
M1-M2. These are not really measures are are shown as data retention items in compliance template P6T1. This standard may not have any associated measures. Remove RA from the measures (really data retention) and the self assessment note in the compliance monitoring process.

EOP-002-0 — Capacity and Energy Emergencies

PSE&G
R3 - R3 should be applied to RA since BA may not have transmission overload information.

Peter Henderson – IMO (Guy Zito – NPCC CP98) (Chris de Graffenried, Ralph Rufrano - NYPA)
R7(b) should be read as Deploying/utilizing all available operating reserve R7(f) should be read as Reducing/shedding load, …….

Mike Kormos – PJM (PSE&G)
M1 - The MEASUREMENT seems to be a Requirement on Compliance Manager

Mike Kormos – PJM (PSE&G)
M2 - The MEASUREMENT is not measurable. Level of Assessment is totally subjective.

Ed Riley - CAISO
Level 4 Non-compliance needs to define what the time frame for a “delay or gap in communications” is. It’s too vague to measure for compliance.

Ed Riley - CAISO
Attachment 1 - Section 1, 1.1 should read “The LSE cannot schedule the resources necessary to provide its customers energy requirements due to, for example…”

Ed Riley - CAISO
Attachment 020-1 - Energy Emergency Alerts BA and Resource Sharing Groups need to be added in the Introduction first sentenece after Load Serving Entity. RA needs to be added to A.2. as a party to be notified. RA needs to be added to B.2.2 as a party to be notified. RA needs to be added to B.3.5.1 as a party to be notified.

Scott Moore – SPP ORWG
In Attachment 020-1 of Standard 020, change "NERC web-site" to RCIS in Sections 2.1, 2.2, 3.1 and 3.2.

Peter Henderson – IMO (Guy Zito – NPCC CP106) (Chris de Graffenried, Ralph Rufrano - NYPA)
Under "Levels of Non-Compliance", it is not clear whether the term “plans” mentioned in Level 3 and Level 4 pertain to the requirements R1 to R10 of this standard or refer to plans prescribed in associated std-025. It appears that compliance items are not mapped as per applicable requirements.

Jerry Nicely, Kathleen Davis – TVA
Insert after Reliability Coordinator, "who has a Balancing Authority"

Jerry Nicely, Kathleen Davis – TVA
Remove "Reliability Coordinator". RC does not own or operate generation. BA has a capacity and energy emergency plan. RC implements EEA process. RA needs to come out.

EOP-003-0 — Load Shedding Plans

FRCC
The Drafting Team asked if the implementation requirements should be moved to other standards focused on emergency operations. As stated earlier, it is important that no changes are made to existing policy with the translation to Version 0.This modification should be considered in Version 1.

PG&E
Purpose - This standard should address requirments of automatic schemes and operaional plans. Implementation of plans should be covered in other requirments as long as they require adherence to the plans.

Phil Creech – Progress
Implementation of load shedding should be moved to policy 5 and 9 requirements

Ray Morella – FirstEnergy
Add UVLS to this requirement.

EOP-004-0 — Disturbance Reporting

Southern Company
R3 - Making the Reliability Authority, Transmission Operator and Balancing Authority all responsible for disturbance reporting seems to be prone to causing confusion over who is doing what. We suggest making the Reliability Authority responsible for Disturbance Reporting with the Transmission Operator and Balancing Authority responsible for 1) identifying potential disturbances for reporting and 2) supporting the Reliability Coordinator in the data collection and analysis phases of the reporting. (May require Ver. 1 Standard)

Mark Heimbach – PPL
The reporting requirements under this Standard should remain with the Regional Reliability Organization or RC/RA. It should not be the obligation of a Generator Operator or Load Serving Entity. The involved GO or LSE should provide information to the reporting authority but not be the ones responsible for ultimately submitting the report.

Roman Carter – Southern Co.
Current Policy requires the Operating Authorities to make the reports to either NERC and possibly to DOE. Is this appropriately applied to the Generator Operator or is it more appropriate for the TOP or BA to report? Does this include Nuclear Plants who already have reporting requirements specified by nuclear regulations?

EOP-005-0 — System Restoration Plans

Gerald Reahlt – Manitoba
The Drafting Team believes this requirement should be clarified to indicate the restoration plan should have as a priority restoring the integrity of the Interconnection.

Mike Kormos – PJM (PSE&G)
Requirements must be practical

Mike Kormos – PJM (PSE&G)
Restoration requires transmission information that BA is not required (by the Functional Model) to have.

Southern Company
Overall, these requirements seem to miss the interdependent nature of restoration planning or implementation in a functional model environment. In particular, the close coupling between black start units and transmission line switching and load pickup following a blackout is not well addressed (if it is addressed at all). This section needs major work. (May require Ver. 1 Standard)

PG&E
Applicability - Should the requirement for Generation Operators to have restoration plans for units that require black start capability be included here? A set of minimum restoration plan elements similar to those being considered for emergency plans should be added.

Ed Riley – CAISO
R1 - "Load Serving Entities" need to also be identified in the Standard as their restoration plans impact others.

Southern Company
R1- Language from Policy 6 applying to Control Areas does not fit well with functional model entities. Balancing Authorities and their associated Transmission Operators can not logically and independently develop plans to "reestablish its electric system." Wording needs to be modified to reflect the interdependencies between functional model entities.

FRCC
Drafting Team Comments - R4 - The Drafting Team believed the restoration plan should include as a priority, restoring the integrity of the Interconnection. As stated earlier, it is important that no changes are made to existing policy with the translation to Version 0.This modification should be considered in Version 1.

Southern Company
R4 - We concur with the Ver. 0 SDT comment to R4 that the restoration of the integrity of the Interconnection should be explicitly emphasized as the penultimate goal of restoration activities.

Guy Zito - NPCC
Potential additional elements of Requirement R5: We are of the opinion that at a minimum, critical existing requirements from "noted potential additional elements" should be made a part of Requirement R5, although they may included as guides in Policy 6B. Existing Template P6T1 outlines most of these requirements as mandatory.

Mike Kormos – PJM (PSE&G)
R8 - Verification of Restoration Plans may be simulated but it can't be tested without severe consequences (Isolating NY to test the Plans for NY may not be smiled upon)

PEPCO
R8 - Actual testing of many restoration procedures is not practical. Operating experience or simulation are frequently the only measures possible without actual shutdown.

FRCC
R9 - Recommend the following revision for clarity: The Reliability Authority, Transmission Operator, and Balancing Authority shall ensure the availability and location of black start capability within its respective Area to meet the needs of the restoration plan.

EOP-006-0 — Reliability Coordination – System Restoration

- No V1 comments

EOP-007-0 — Establish, Maintain, and Document a Regional Blackstart Capability Plan.

Bob Jones, SERC Planning Stds Subcommittee
Terry Blackwell, SCPSA
The Testing Frequency requirement listed in R1-1c should clarify that generator owners who own less than three blackstart units do not have to retest the same unit consecutively (every year) as long as the generator owner tests its blackstart unit(s) every three years.

EOP-008-0 — Plans for Loss of Control Center Functionality

Robert Snow
There needs to be a requirement on how the operating staff knows that they have lost control center functionality.

Robert Snow
Under R1, the continency plan should addresses how monitoring and control of facilities will be achieved and provide a maximum time for restoration of the monitoring and control function.

EOP-009-0 — Documentation of Blackstart Generating Unit Test Results

Ed Davis Entergy

R4-2 should include that the test results will be provided to Reliability Authority and Transmission Operators in place or Regional Reliability Council.

FAC-001-0 — Facility Connection Requirements

Al DiCaprio
Delete 53.1 Nothing in this standard relates to a NERC-level requirement. This standard is based on RRO setting the requirements but does nothing, from a NERC perspective, of defining whether those RRO requirements are good or bad. This standard punishes RROs for not providing NERC documentation of information that NERC doesn't do anything with nor has a measure for.

PSE&G
Some of these requirements are by FERC filing or state mandate, not just NERC.
This needs to apply to the Transmission Owner or its designated agency such as an RTO/ISO.
Need to clarify requirements of end-users of the transmission system
Removed requirement to not degrade system when making interconnections (No impairments)

Jeffrey Miller, WECC Reliability Subcommittee
Dr. J. Kondragunta, So CA Edison
Phil Park, BCTC
Chifong Thomas
Kent McCarthy, Idaho Pwr Co
If this standard is kept, R1-1 and R1-2 should be merged

Thomas Mielnik, MAPP PSDWG
In R1-3 and in the Timeframe for the Compliance Monitoring Process, 5 business days is not long enough. If a key individual is unavailable, the standard may be violated. MAPP PSDWG recommends that the recommends that the 30 calendar days from 53.2 be used throughout the standard.

Vinod Kotecha - Con Edison Company of New York CEPD
Norman Mah - Con Edison Company of New York CEPD
Edwin Thompson - Con Edison
Rebecca Adrienne Craft - Con Edison Company of New York CEPD
Compliance Item 1.2. Five business days may be too onerous for Facility Connection Requirements. Suggest revision to at least 30 days.

MAPP Planning Standards Subcommittee
Is there are rational between using 5 business days for R1-3 and 30 days for R2-2? Preference would be to use 30 days throughout standard.

John Blazekovich, Exelon
R1 Exelon Corporation suggests that Standard 051 be moved quickly to Version 1 to provide more direction as to when an assessment is required for an interconnection, especially for load-serving entities.

Robert Snow
In addition to not providing an impact study for a new facility, a level 4 violation is having a completed study with assumptions that are not consistent with present conditions.

FAC-002-0 — Coordination of Plans for New Facilities

Robert Snow, Independent Contributor
Add "transmission owner" between individual and system planning criteria.

MAPP Planning Standards Subcommittee
Is there are rational between using 5 business days for R1-3 and 30 days for R2-2? Preference would be to use 30 days throughout standard.

Bob Millard, MAIN
This section should not move forward in Version 0 since it is essentially already covered by Version 0 STD 051

Vinod Kotecha - Con Edison Company of New York CEPD
Norman Mah - Con Edison Company of New York CEPD
Edwin Thompson - Con Edison
Rebecca Adrienne Craft - Con Edison Company of New York CEPD
R1. "Power Pool?". Should also include ISO and RTOs.

PSE&G
R2-1 Evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems [ADD "in terms of Loss of Load Event probabilities and deliverability"]. What would be considered evidence that the parties cooperated? It is not clear how the Functional Model would work in a state with BGS supply (Utilities are not LSEs). Identify that any new project shall not reduce total transfer capability.

Robert Snow
This is a good example of the compliance not being consistent with the impact on reliability. If an impact study is completed but the underlying assumptions about the system have completely changed, the To would be in compliance but not have the slightest idea of how the project impacted the reliability of the presently planned power system.

FAC-003-0 — Vegetation Management Program

Ed Davis Entergy
Requirements should refer to Reliability Authority rather than Regional Reliability Council.

Guy Zito NPCC
Pete Henderson IMO
The standard 072 mentions that vegetation related outages to be reported to "Regional Reliability Council". We are of the opinion that the Transmission Owner should report the vegetation related outages to its concerned "Reliability Authority" in order to be consistent with all present practices and process. Accordingly, we suggest the same to be incorporated in the applicable section 1 of standard 072 as follows: "… to its Reliability Authority all vegetation-related outages …" shall be read instead of "… to its Regional Reliability Council all vegetation-related outages …".

Guy Zito, NPCC-CP9
Ralph Rufrano, NY Pwr Auth
Chris de Graffenried, NY Pwr Auth
Peter Lebro, National Grid
Peter Henderson, IMO

Compliance Monitoring Process-
The basic goal of reporting vegetation contact is to more quickly identify the proximity of growing vegetation to critical transmission, and the threat posed, and to further identify possible trends suggesting poor vegetation management on the part of a given TO. It is the opinion of the NPCC Task Force on Coordination of Operation that the above exceptions permitted in the current standard contradict the very intent of the vegetation reporting program and considerably weaken the effort. Such exceptions must not be permitted if the initiative is to succeed.

Karl Kohlrus
The Levels of Non-Compliance is not in a consistent format with other standards.

FAC-004 -0 — Methodologies for Determining Electrical Facility Ratings

Chifong Thomas
Peter Mackin, TANC
The terms -facility-, -electrical facility-, and -transmission facility are used interchangeably throughout the Requirements and Measurments sections. We suggest just using one term throughout the document.

Tracy Edwards, BPA
Deanna Phillips, BPA
Deborah Linke, US Bureau of Reclamation
Rebecca Berdahl, BPA
Requirement R1-1, item a should included the words -as applicable for each owner- after the words -the items listed-. Not all owners will have all the pieces of equipment listed.

Deanna Phillips, BPA
Rebecca Berdahl, BPA
Requirement R1-1 also includes the requirement for Generator owners to provide data. However the list does not include any generation equipment. Although information on the generation equipment is necessary, it is not included in the existing standard. This needed information should be flagged as missing for the Transmission Plan SAR 500 Team to address.

Ed Riley, CA-ISO
Add Reliability Authority to list of parties to receive documentation in addition to the RRO and NERC.

FAC-005-0 — Electrical Facility Ratings for System Modeling

Bob Millard, MAIN
This section should not move forward in Version 0 since it is essentially already covered by Version 0 STD 058. In addition it is more procedure/data oriented, not really stand alone "standard" material but more tools or reference material for executing a standard

Karl Kohlrus
This standard applies to Generator Owners. I suppose this means the transmission-related terminal equipment such as transformers, breakers and substation equipment. There should be a separate standard on the rating of generating equipment including both MW and MVAR. Such a standard should also include standards for rating intermittent resources such as wind farms.

Chifong Thomas
Peter Mackin, TANC
The terms -facility-, -electrical facility-, and -transmission facility are used interchangeably throughout the Requirements and Measurments sections. We suggest just using one term throughout the document.

INT-001-0 — Interchange Transaction Tagging

Ed Riley
CAISO
R1 - 2.1 P3T3 goes directly to Level 4 violations. The CAISO agrees with the sanctions for a tag violation, but believes the practice as written is too stringent and there should be Level 1 through 4 violations. This should be identified as a Regional Difference.

Raj Rana
AEP
R1 - Policy says that Dynamic Interchange Schedules should be tagged (doesn't say who has to do it). R1 and R4 says that the Load PSE is responsible. This is a new restriction.

R1 - Policy says that Dynamic Interchange Schedules should be tagged (doesn't say who has to do it). R1 and R4 says that the Load PSE is responsible. This is a new restriction.

FRCC
R2 - Clarification of the following is required: … such as through prearranged reserve sharing agreements or other arrangements…Does this mean that reserves will need to be tagged is an entity is part of a reserve sharing group, or, does it mean reserves are tagged if purchased from another member of the reserve sharing group when the purchaser cannot cover their required reserves?

Kevin John Conway - Grant County PUD No.2
Greg B. Lange - Grant County PUD No.2
The original wording from Policy 3A.2.1 should be re-inserted into Version 0 Standard INT-001, Requirement 2.2.

Robert D. Schwermann - Sacramento Municipal Utility District
E. Nick Henery - Sacramento Municipal Utility District
Errata change, Version 0 Standard INT-001, Requirement 2.2, is a substantial change to the requirements of the original operating policies. The NERC IS has agreed to review this requirement and we support the efforts of the IS to clear up this issue of tagging inside a 60 minute time frame. It is also understood that this change should be completed by April 05.

Robert Kondziolka - Salt River Project
The original wording from Policy 3A 2.1 should be used in version 0 Standard INT-001, Requirement 2.2. Changes or clarifications via the errata sheet can be more properly addressed through the submittal of a SAR using the Version 1 process to provide adequate industry input regarding the interpretations of the requirements.

Gene Henneberg - Sierra Pacific Power Company
This standard seems to be ambiguous about the time frame when generation must be scheduled.

James Keller - Wisconsin Electric Power Marketing
Linda Horn - Wisconsin Electric Power Company
Standard INT-001 R2.2 states: " To replace unexpected generation loss, such as through prearranged reserve sharing agreements or other arrangements, and all emergency

Transactions to mitigate System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) violations. Such interchange shall be tagged within 60 minutes from the time at which the Interchange Transaction begins."
Existing Policy 3.A.2.1 states: "Interchange Transactions established to replace unexpected generation loss, such as through prearranged reserve sharing agreements or other arrangements, are exempt from tagging for 60 minutes from the time at which the Interchange Transaction begins (tagged by the Sink Control Area)."
The Standard INT-001 R2.2 should be changed to continue the "are exempt from tagging for 60 minutes".

Aquila
Aquila suggests that the original wording from Policy 3A 2.1 should be used in the Version 0 Standard. *(The V0 drafting team recommend that the Interchange Subcommittee immediately prepare a SAR to propose revisions to address the remaining ambiguities before, or as soon as possible after, the implementation of the Version 0 standards.)*

WECC Interchange Subcommittee
R2 - Clarify the last sentence - Such interchange shall be "tagged within 60 minutes" from the time that the interchange transaction begins

WECC Interchange Subcommittee
2.1 P3T3 - The P3T3 template goes directly to Level 4. The WECC ISAS agrees with sanctions for tag violations, but think the practice as written is too stringent and there should be level 1 through 4 violations

Kent McCarthy – Idaho Power
Requirement R2b. It appears that this requirement changes current policy. We recommend that if a change is necessary you consider allowing for time frames longer than one hour for dynamic or reserve tags that may require longer than one hour for adjustment.

John Simonelli - IS
Comment on Template 010 Why do we once again require the sink BA to put tags in for a commercial transaction? The example is jointly owned units, well why not the majority owner PSE or a designated PSE by the unit owners or anyone but the BA? If this unit is commercially sold to entities outside the BA boundary, how does the BA know where it ends up, who is buying it and what transmission arrangements have been made outside the BAs boundary? It seems other than emergency, reserve sharing, loss of gen/load or inadvertent, the BA should be left OUT of the tagging game. This is a commercial venture and if someone from the commercial sector fails to tag it, it doesn't flow and someone losses $$$. Bet they tag in next time. The BA has insufficient information to complete the tag beyond their borders. The problem is in today's world the CA most likely has enough information to tag a transaction like this. I am not as confident the BA under the FM will have that capability nor will they have the authority under the BA Standards. Does that standard require the BA to do anything more than balance his generation, load, losses, reserves and interchange? If I'm a BA (remember under the FM the BA does not have wide area purview like many of today's CAs have), I may not be able to do this. Should we write a standard that requires an entity to do something they can't do under the FM??? Remember this is not simply an exercise in converting the Policies to Standards, it's also supposed to integrate the FM. We will have BAs under the version 0 standards with compliance measures. I want to make sure we don't put the BA between a rock and a hard place. Comment on Template 011 The Purpose of templates 011 states that this standard is to provide the data to all entities needing to make a reliability assessment. In the

body of the standards we specifically spell out what the TSP and BA need to do with the data. Just curious, what about what the TO needs to do, doesn't the TO (or RA/RC) do the true reliability assessment, i.e., can these MW actually reliably flow on my system at this time? The TSP Functional Model Technical Specifications document actually states, "The TSP does NOT itself have a role in maintaining system reliability in real time – that is the RA and TOs responsibility." One could argue spelling out what the TO (or RA/RC) does is more important than what the TSP does, in fact one could argue a lot of what the TSP does in this standard is "commercial" not" reliability" based.

Marylin Franz – Sierra Pacific
Need to allow for times when tags need to be submitted beyond one hour such as dynamic or reserve tags that need adjustment outside a one hour time frame. R2B appears to change current policy which was not in the scope of version zero

Don Tench - IMO
There is a concern about the e-tagging compliance measures/levels in INT-001-0 (Interchange Transaction Tagging). It needs to be noted that the associated original template P3T3 included non-compliance levels i.e. L1 and L4. These levels of non-compliance from original template P3T3 have not been mapped/translated into this standard INT-001-0. However, if mapped, we were concerned that not meeting the measure 100 % of the time would result in a L4 non-compliance level. This seemed overly severe. Nevertheless, it will be appropriate to include reasonable/practical levels of non-compliance.

> IMO’s Proposed Recommendation: We recommend that the levels of non-compliance for this standard-INT-001-0 should be assessed/reviewed for their inclusion in the near future, and if prescribed should be reasonable and of practical nature.

INT-002-0 — Interchange Transaction Tag Communication and Assessment

- No V1 comments

INT-003-0 — Interchange Transaction Implementation

- No V1 comments

INT-004-0 — Interchange Transaction Modifications

Alan Boesch – NPPD
R1 - According to the functional model the Transmission Operator is the transmission entity involved in transmission modifications for reliability events. The Transmission Service Provider should be removed and replaced by the TOP.

SRP
R1 - It may be a good idea to clearly define some requirements on establishing a reliability limit. If it is not proper to allow denial of a tag cutail request then perhaps that should be spelled out in the requirements. Tag cutail requests currently qualify for passive approval even if late yet an entity could deny the request. The NERC Interchange Subcomittee addressed this issue in a letter submitted on 6/10/02 (continued in next field).(cont. from above) From NERC IS letter. Curtailment orders may be denied only for the following two reasons: 1. The order requests actions in the past (for example, an order to curtail a transaction five minutes ago). 2. The order for curtailment cannot be reliably implemented. In either case, the denying party should immediately issue its own curtailment order to effect the transaction curtailment.

Brandian – ISO-NE
Measures - Associated Measure, Compliance Monitoring Process and Levels of Non Compliance are missing and needs to be defined in this standard simultaneously

Eric Grant – Progress Energy
The Levels of Non Compliance are not realistic for tags associated with dynamic schedules. The purpose of the tag is to reflect the power exchange that is currently accruing on the power system, but currently it is possible that the tag can get held or delayed which will result in a non compliance.

Eric Grant – Progress Energy
The Levels of Noncompliance and reset period are overly stringent for Balancing Authorities with multiple dynamic schedules. As currently written, failure to update a single tag requires performance over a full calendar year without a subsequent violation to achieve full compliance. Suggest reducing the compliance reset period to 3 months.

Marylin Franz – Sierra Pacific (Robert Schwermann – WECC IS)
Level 1- For tag volumes greater than 500 tags per month, the number of noncompliant events was greater than 2% but less than or equal 3% of the total number of tags processed(approved tags plus denied tags) during the calendar month. For tag volumes less than or equal to 500 tags per month the number of noncompliant events was greater than 10 but less than or equal to 15. Level 2- For tag volumes greater than 500 tags per month, the number of noncompliant events was greater than 3% but les

Marylin Franz – Sierra Pacific (Robert Schwermann – WECC IS)
Level 2- For tag volumes greater than 500 tags per month, the number of noncompliant events was greater than 3% but less than or equal to 4% of the total number of tags processed during the calendar month. For tag volumes less than or equal to 500 tags per month, the number of noncompliant events was greater than 15 but less than or equal to 20.
Marylin Franz – Sierra Pacific (Robert Schwermann – WECC IS)
Level 3- For tag volumes greater than 500 tags per month, the number of noncompliant events was greater than 4% but less than or equal to 5% of the total number of tags processed during

the calendar month. For tag volumes less than or equal to 500 tags per month, the number of noncompliant events was greater than 20 but less than or equal to 25.

Marylin Franz – Sierra Pacific (Robert Schwermann – WECC IS)
Level 4- For tag volumes of greater than 500 tags per month the number of noncompliant events was greater than 5% of the total number of tags processed during the calendar month. For tag volumes less than or equal to 500 tags per month the number of noncompliant events was greater than 25.

Marylin Franz – Sierra Pacific (Robert Schwermann – WECC IS)
The levels of noncompliance are too stringent and should be based on a percentage. The WECC RMS sanctionable criteria has been shown to be equitable and could be used as a model. Following in several text boxes is the suggested criteria which WECC has adopted. There would probably be a request for a regional difference to comply with WECC RMS criteria if NERC criteria is not compatible.

Robert Schwermann – WECC IS
The WECC has its Reliability Management System (RMS) currently in place. Its sanctionable criteria has been shown to be equitable and should be used as a model. The text is the following boxes is the criteria which WECC has adopted. WECC may request a regional difference to preserve the WECC's RMS criteria if NERC criteria is not compatible.

IRO-001-0 — Reliability Coordination – Responsibilities and Authorities

Brandian – ISO-NE (Guy Zito – NPCC)
R8 - At the end of R8, the inability to perform the directive AND WHY should be communicated to the RA.

Brandian – ISO-NE (Guy Zito – NPCC)
Please clarify and provide example(s) of what is meant by the “interest of other entity”.

IRO-002-0 — Reliability Coordination – Facilities

Guy Zito – NPCC (Brandian – ISO-NE)
R5 - Please clarify/define what is ”synchronized information system.”

Guy Zito – NPCC (Brandian – ISO-NE)
R7 - Please clarify/define what constitutes “adequate” analysis tools and “wide-area overview”.

Mike Kormos – PJM (PSE&G)
R7 - adequate analysis tools is not a 'crisp' requirement

Mike Kormos – PJM (PSE&G)
R7 - Requirements must be practical

Al DiCaprio – MAAC
The requirement is not measureable regarding "easily understood" or "Particular emphasis". Would suggest wording such as : "…provide information on alarm management and awareness, …." similarly with R7 - drop the word 'adequate'.

IRO-003-0 — Reliability Coordination – Wide Area View

- No V1 comments

IRO-004-0 — Reliability Coordination – Operations Planning

Al DiCaprio – MAAC
Change "pay particular attention to " to "monitor"

IRO-005-0 — Reliability Coordination – Current Day Operations

Ed Riley – CAISO
R10, R11, R12 - Regarding directing BA's to return to CPS and DCS compliance, what Standard (or Policy) will empower the RA to do this? The BA could tell the RA "I'm having a bad CPS day, but I will be O.K. for the year (CPS1) and the month (CPS2)" Is the RA expected to direct the TO they must manually shed load to help the BA meet DCS? At what point in the post disturbance recovery does the RA issue this directive? T+15? Or T+10 so no violation occurs? These actions, if that is what this Standard is saying, will require re-writing the Empowerment Agreements that are currently in place, which will be a lengthy process with uncertain results.

IRO-006-0 — Reliability Coordination – Transmission Loading Relief

Scott Moore – SPP ORWG
The usage of the TLR Log as contained in Section 1.8 of Attachment 039-1 is not consistent with TLR Log definition in the Glossary. Although Section 1.8 is consistent with current Policy, this log is no longer used in actual practice. Actual practice is more in line with that captured in the definition in the Glossary.

Scott Moore – SPP ORWG
Appendix C of Attachment 039-1 is no longer used. See inconsistency mentioned above.

MOD-001-0 — Documentation of TTC and ATC Calculation Methodologies

Jeffrey Miller, WECC Reliability Subcommittee
Dr. J. Kondragunta, So CA Edison
Phil Park, BCTC
Kent McCarthy, Idaho Pwr Co
This standard should be deleted and not be part of the reliability standards. This should be covered by NAESB and FERC.
The reliability constraint should be that the calculation of the TTC must meet all of the reliability standards. 054.1 as it stands now does not require meeting the standards.

Al DiCaprio, MAAC
Delete "in conjunction with its members". Membership and governance of the RROs is not subject to NERC's approval.

Frank McElvain
Tri-State G&T
Under “Applicability”; there is no list of systems exempt from posting ATC, though it is stated there are such systems. The text should either quote a statute or reference a standard that describes parties which are required or exempt from posting ATC, or the criteria should be succinctly stated in the text of this Standard.

PSE&G
These standards need to apply more broadly than regions. Probably needs to be with balancing or scheduling authority to be consistent with markets.

Frank McElvain
Tri-State G&T
Suggest the wording be changed to read as follows: “If Total Transfer Capability or Available Transfer Capability value normally change over different time horizons (such as hourly, daily, or monthly) describe assumptions and calculation methods”.

Vinod Kotecha - Con Edison Company of New York CEPD
Norman Mah - Con Edison Company of New York CEPD
Edwin Thompson - Con Edison
Rebecca Adrienne Craft - Con Edison Company of New York CEPD
Item R.1.7 will depend upon the dispatch. In most cases an RRO does not have the “bids” or cannot access them so how is this work to be performed? Please clarify.

Without having the “bid” data, the Transmission Provider cannot meet the “Requirement” unless NERC is willing to say that the bids will be provided to TOs and TPs.

MOD-002-0 — Review of TTC and ATC Calculations and Results

Jeffrey Miller, WECC Reliability Subcommittee
Dr. J. Kondragunta, So CA Edison
Phil Park, BCTC
Kent McCarthy, Idaho Pwr Co
This standard should be deleted and not be part of the reliability standards. This should be covered by NAESB and FERC.
The reliability constraint should be that the calculation of the TTC must meet all of the reliability standards. 054.2 as it stands now does not require meeting the standards.
The reliability constraint should be that the calculation of the TTC must meet all of the reliability standards. 054.3 as it stands now does not require meeting the standards.

PSE&G
These standards need to apply more broadly than regions. Probably needs to be with balancing or scheduling authority to be consistent with markets.

Paul Arnold, BPA
should include requirements for TSPs to follow TTC/ATC calculation methodology developed by regions. If this is not a requirement now, it should be flagged for follow-up for the corresponding Version 1 process.

Frank McElvain, Tri-State G&T
As an example of how compliance evidence sections should read, change this section to read as follows: "The Regional Reliability Council shall have evidence in the form of a mail receipt returned from NERC indicating it complied with NERC's request in accordance with 054-R2-3."

MOD-003-0 — Procedure for Input on TTC and ATC Methodologies and Values

PSE&G
These standards need to apply more broadly than regions. Probably needs to be with balancing or scheduling authority to be consistent with markets.

Frank McElvain
Tri-State G&T
The recourse for a customer must be specified in this standard. One logical recourse would be controlled access to data and analysis used to determine ATC.

MOD-004-0 — Documentation of Regional CBM Methodologies

Robert Snow, Independent Contributor
It is only logical that CBM be coordinated between regions

Frank McElvain
Tri-State G&T
Change "…units within…" to "…units which affect deliveries into or within…"

Al DiCaprio, MAAC
Delete "in conjunction with its members". Membership and governance of the RROs is not subject to NERC's approval.

Al DiCaprio, MAAC
Delete item 'a': "Specify that the method used … consistent with its generation planning criteria." How can this be a standard if neither NERC nor all of the RROs have generation planning criteria?

Vinod Kotecha - Con Edison Company of New York CEPD
Norman Mah - Con Edison Company of New York CEPD
Edwin Thompson - Con Edison
Rebecca Adrienne Craft - Con Edison Company of New York CEPD
Item BR1.3 is too restrictive. Why should the Transmission Service Provider's CBM be restricted to those units within the Transmission Service Provider's System is not clear. Suppose a large generating plant in an adjacent system causes more of a problem to the Transmission Service Provider? It should have the right to look at the worst generator contingency affecting its facilities.

MOD-005-0 — Procedure for Verifying CBM Values

Boisvert TransEnergie
Brandian ISO-NE
"Certain systems that are not required to post Available Transfer Capability values are exempt from this Standard." Should this statement not be included also in 55 and 56?

Bill Bojorquez, ERCOT
Similar to ATC, Regions may be exempt from calculating Capacity Benefit Margin (CBM). The Applicability should read: "Regional Reliability Council (Certain systems that are not required to post CBM values are exempt from this Standard."

Travis Bessier, TXU
Add exemption language as follows: (Certain systems that are not required to post Available Transfer Capability values are exempt from this Standard.)

PSE&G
Need to make it clear that the ATC in a region covers a geographic region, not just the members of the region. What is the relationship between shared reserves and CBM?

Frank McElvain, Tri-State G&T
Change this section to read as follows: "Indicate the frequency under which the review shall be implemented or the system conditions which would dictate that review is necessary."

Frank McElvain, Tri-State G&T
Change to read as follows: "Require updated Capacity Benefit Margin values to be made available to the Regions, NERC and transmission users."

Al DiCaprio, MAAC
Delete "in conjunction with its members". Membership and governance of the RROs is not subject to NERC's approval.

Al DiCaprio, MAAC
Item 'b' delete "to ensure that the most current CBM values are available to users." CBM is not made available to users.

Narinder Saini, Entergy
R2-1 d), R2-2, R2-3: These three sections do not appear to contain any substative differences. Please clarify the sections so that the differences are more obvious.

MOD-006-0 — Procedure for the Use of CBM Values

Frank McElvain
Tri-State G&T
CBM is only an import quantity. The text of 55-R3-1 and 55-R3-2 should be changed to reflect this.

Gene Henneberg - Sierra Pacific Power Company
The Capacity Benefit Margin (CBM) unduly restricts scheduling ability to the detriment of reliability. The transmission owner should be free to choose the order in which to use reserve components. In addition, it seems more appropriate that the discussion of CBM should be in the Operating Standards.

MOD-007-0 — Documentation of the Use of CBM

Mike Gildea, Constellation
R4-1 “Each Transmission Service Provider that uses Capacity Benefit Margin (CPS) shall report the use of CPS by the Load Serving Entities’ loads on it system, except for CPS sales as non-firm transmission service.” NEED MORE DEFINTION ON TO WHOM THIS IS REPORTED AND HOW CLOSELY THE POSTING FOLLOWS ITS’ USE IN ORDER TO PROVIDE INFORMATION THAT IS USEFUL AND ALLOWS COMPARAISION

Narinder Saini, Entergy
Compliance Monitoring Process: Timeframe: After the text presently in the standard, add the words (the documentation shall be posted on a website accessible by the Regional Reliability Organizations, NERC and the transmission users in the electricity market).

MOD-008-0 — Documentation and Content of Each Regional TRM Methodology

Boisvert, TransEnergie
Brandian ISO-NE
"Certain systems that are not required to post Available Transfer Capability values are exempt from this Standard." Should this statement not be included also in 55 and 56?

Travis Bessier TXU
Add exemption language as follows: (Certain systems that are not required to post Available Transfer Capability values are exempt from this Standard.)

Bill Bojorquez, ERCOT
Similar to ATC and CBM, Regions may be exempt from calculating Transmission Reliability Margin (CBM). The Applicability should read: "Regional Reliability Council (Certail systems that are not required to post Transmission Reliability Margin values are exempt from this Standard."

Al DiCaprio, MAAC
Delete "in conjunction with its members". Membership and governance of the RROs is not subject to NERC's approval.

MOD-009-0 — Procedure for Verifying TRM Values

Al DiCaprio, MAAC
Item 'b' Delete "to ensure …values available to users."

Al DiCaprio, MAAC
Item 'd' delete - Margin values not provided to users.

MOD-010-0 — Steady-State Data for Transmission System Modeling and Simulation

Bob Millard, MAIN
This section should not move forward in Version 0. More procedure/data oriented, not really stand alone "standard" material but more tools or reference material for executing a standard

PSE&G
While data on equipment is understandable, schedules for transactions between regions but within the same RTO do not make sense.

Thomas C. Mielnik - MidAmerican Energy Company
We believe that the standards continue to have non-deal-killer issues, such as . . . need to refer to confidentiality for Standards of Conduct or Critical Energy Infrastructure Information purposes in MOD-010-0 . . .

MAPP Planning Standards Subcommittee
Add a clause to reflect the need to protect the confidentiality of data. Refer to FERC Critical Energy Infrastructure Information provisions.

MAPP Planning Standards Subcommittee
Each process calls for reporting procedures within 30 business days. However the levels of non-compliance do not use on-time or lateness as an aspect of non-compliance.

MAPP Planning Standards Subcommittee
Make the levels of compliance more consistent from section to section of this same standard. (Other sections now are numbered as MOD-010 through MOD-014)

Ed Riley, CA-ISO
Remove NERC from the list of parties the data shall be provided to.

Thomas Mielnik, MAPP PSDWG
Make the Levels of Non-compliance consistent.

MOD-011-0 — Regional Steady-State Data Requirements and Reporting Procedures

Bob Millard, MAIN
This section should not move forward in Version 0. More procedure/data oriented, not really stand alone "standard" material but more tools or reference material for executing a standard

PSE&G
R2-1.2 - Add induction generators; governor dead band, droop and limits; generator step up transformer data and taps; metering; and auxiliary system limitations on generator voltage.

MAPP Planning Standards Subcommittee
Make the levels of compliance more consistent from section to section of this same standard. (Other sections now are numbered as MOD-010 through MOD-014)

MAPP Planning Standards Subcommittee
Add a clause to reflect the need to protect the confidentiality of data. Refer to FERC Critical Energy Infrastructure Information provisions.

MAPP Planning Standards Subcommittee
Each process calls for reporting procedures within 30 business days. However the levels of non-compliance do not use on-time or lateness as an aspect of non-compliance.

PSE&G
Add a section on static VAR devices
Add no-load taps for voltage and angle; and type of cooling (FOA units can not be used during black start)

Bob Jones, SERC Planning Stds Subcommittee
Roman Carter, Southern
Terry Blackwell, SCPSA
Add the following after the first sentence: "The procedures shall include the identification of the entities responsible for the reporting of the data (referred to in 058.1 as 'Responsible Entity')".

Ed Riley, CA-ISO
In b, replace (net real and reactive power) with (gross real and reactive power).

Ed Riley, CA-ISO
In d, add line status, transformer ratings, and metering locations.

Norman Mah - Con Edison Company of New York CEPD
Edwin Thompson - Con Edison
Rebecca Adrienne Craft - Con Edison Company of New York CEPD
Kotecha - Con Edison Company of New York CEPD
Requirements Item R1.1 : Security issue : We should not require “locations” of substations to be made public anymore. (since 9/11)

MOD-012-0 — Dynamics Data for Transmission System Modeling and Simulation

Bob Millard, MAIN
This section should not move forward in Version 0. More procedure/data oriented, not really stand alone "standard" material but more tools or reference material for executing a standard

MAPP Planning Standards Subcommittee
Make the levels of compliance more consistent from section to section of this same standard. (Other sections now are numbered as MOD-010 through MOD-014)

MAPP Planning Standards Subcommittee
Add a clause to reflect the need to protect the confidentiality of data. Refer to FERC Critical Energy Infrastructure Information provisions.

MAPP Planning Standards Subcommittee
Each process calls for reporting procedures within 30 business days. However the levels of non-compliance do not use on-time or lateness as an aspect of non-compliance.

Thomas C. Mielnik - MidAmerican Energy Company
We believe that the standards continue to have non-deal-killer issues, such as . . . need to refer to confidentiality for Standards of Conduct or Critical Energy Infrastructure Information purposes in . . . MOD-012-0. . .

MOD-013-0 — RRO Dynamics Data Requirements and Reporting Procedures

Bob Millard, MAIN
This section should not move forward in Version 0. More procedure/data oriented, not really stand alone "standard" material but more tools or reference material for executing a standard

Robert Snow
The use of a conservative model is applicable.

MAPP Planning Standards Subcommittee
Add a clause to reflect the need to protect the confidentiality of data. Refer to FERC Critical Energy Infrastructure Information provisions.

MAPP Planning Standards Subcommittee
Each process calls for reporting procedures within 30 business days. However the levels of non-compliance do not use on-time or lateness as an aspect of non-compliance.

Bob Jones, SERC Planning Stds Subcommittee
Terry Blackwell, SCPSA
Add the following after the first sentence: "The procedures shall include the identification of the entities responsible for the reporting of the data (referred to in 058.3 as 'Responsible Entity')".

Kirit Shah, Ameren
Item 'c' delete "as a function of frequency and voltage" Not everyone has this and there is no NERC standard for such characteristics.

Thomas Mielnik, MAPP PSDWG
In R4-2, five business days is not long enough. If a key individual is unavailable, the standard may be violated.

MAPP Planning Standards Subcommittee
Make the levels of compliance more consistent from section to section of this same standard. (Other sections now are numbered as MOD-010 through MOD-014)

Vinod Kotecha - Con Edison Company of New York CEPD
Norman Mah - Con Edison Company of New York CEPD
Edwin Thompson - Con Edison
Rebecca Adrienne Craft - Con Edison Company of New York CEPD
R1.1 should be changed to read: Generator Owners shall report unit-specific dynamics data for generators....

MOD-014-0 — Development of Interconnection-Specific Steady State System Models

Robert Snow
Solved cases without any violations should be the basic requirement.

Frank McElvain, Tri-State G&T
The terms "near-term" and "long-term" are ambiguous. Suggest defining near-term to be within five years and long-term to be beyond ten years.

MAPP Planning Standards Subcommittee
These levels are very detailed. The levels in other sections of this standard are not as detailed. Make the levels of compliance more consistent from section to section of this same standard.

MAPP Planning Standards Subcommittee
Add a clause to reflect the need to protect the confidentiality of data. Refer to FERC Critical Energy Infrastructure Information provisions.

MAPP Planning Standards Subcommittee
Each process calls for reporting procedures within 30 business days. However the levels of non-compliance do not use on-time or lateness as an aspect of non-compliance.

MOD-015-0 — Development of Interconnection-Specific Dynamics System Models

MAPP Planning Standards Subcommittee
Add a clause to reflect the need to protect the confidentiality of data. Refer to FERC Critical Energy Infrastructure Information provisions.

MAPP Planning Standards Subcommittee
Each process calls for reporting procedures within 30 business days. However the levels of non-compliance do not use on-time or lateness as an aspect of non-compliance.

MAPP Planning Standards Subcommittee
These levels are very detailed. The levels in other sections of this standard are not as detailed. Make the levels of compliance more consistent from section to section of this same standard. (Other sections now are numbered as MOD-010 through MOD-014)

MOD-016-0 — Actual and Forecast Demands, Net Energy for Load, Controllable DSM

Robert Snow, Independent Contributor
All Actual and Forecast Demands must include the respective weather data to be useful. Any entity responsible for reliability has included weather data, such as THI, both the actual and forecast data.

Thomas Mielnik, MAPP PSDWG
Levels of non-compliance should be made consistent.

MOD-017-0 — Aggregated Actual and Forecast Demands and Net Energy for Load

- No comments for V1

MOD-018-0 — Reports of Actual and Forecast Demand Data

Frank McElvain, Tri-State G&T
This is a good step in the right direction, but the term "uncertainties" is ambiguous. Would this be standard load forecast error due to statistical methods used, or normal variations due to weather or economic conditions, or some other quantity? The requirement for addressing uncertainties in load data submittals should be limited to reporting the magnitude of load forecast trends, and any allowances included for load forecast uncertainty. In other words, the report documentation should include • average annual load growth for the first 5 years of the forecast period, and • a demand variation allowance, based on how much the actual peak load has differed from forecast load in prior years. These quantities might best be reported on a percentage basis. Here is text for Section 5 that would accomplish this: b. specify the percent average annual load growth for the first five years of the forecast period c. specify any margin used to reflect maximum likely amount by which actual peak demands could exceed forecast values.

Thomas C. Mielnik - MidAmerican Energy Company
We believe that the standards continue to have non-deal-killer issues, such as . . . need to refer to confidentiality for Standards of Conduct or Critical Energy Infrastructure Information purposes in . . . MOD-018-0 through MOD-020-0.

MOD-019-0 — Forecasts of Interruptible Demands and DCLM Data

Kirit Shah, Ameren
The Level 4 non-compliance seems a bit harsh (as compared to other Level 4's) for not having some data.

Thomas C. Mielnik - MidAmerican Energy Company
We believe that the standards continue to have non-deal-killer issues, such as . . . need to refer to confidentiality for Standards of Conduct or Critical Energy Infrastructure Information purposes in . . . MOD-018-0 through MOD-020-0.

MOD-020-0 — Providing Interruptible Demands and DCLM Data

Thomas C. Mielnik - MidAmerican Energy Company
We believe that the standards continue to have non-deal-killer issues, such as . . . need to refer to confidentiality for Standards of Conduct or Critical Energy Infrastructure Information purposes in . . . MOD-018-0 through MOD-020-0.

MOD-021-0 — Accounting Methodology for Effects of Controllable DSM in Forecasts

- No comments for V1

PER-001-0 — Operating Personnel Responsibility and Authority

Southern Company
Compliance Monitoring Process
The Data Retention requirement for this standard should be 1 year. The probability exists that over time, the job description and perhaps other documentation will be modified. There should not be a requirement to keep past versions of authorizing documents for an indefinite period of time.

Bill Squibb – ECAR
In the Compliance Monitoring Process… if the Reset Period is One Calendar Year, then why is the Data Retention Permanent. In addition, what kind of data is considered for Data Retention. Surely a 10-year old Job Description that has been updated several times does not need to be retained permanently.

PER-002-0 — Operating Personnel Training

Mike Kormos – PJM (PSE&G)
Measure could be that one has a documented program.

Mark Klohonatz – ECAR
Applicability - Only the Reliability Authority, Balancing Authority, and Transmission Operator Functional Roles are listed in the Draft #2 Version 0 Standard, however, System Operators who perform the same reliability functions also exist at other entities. Therefore, if it can not be shown as applicable to any operators performing specific functions, the applicability of this standard should include the Transmission Owner, Generator Owner, Generator Operator, and Load Serving Entity also.

Mark Klohonatz – ECAR
Article R1.2 of the new standard refers to … at least five days per year of training and drills in system emergencies. Given that formal interpretations have been communicated to clarify the implementation of this requirement as to be completed with 32 contact hours, we believe that the phrase five days should be replaced with the more specific phrase 32 hours.

Robert Williams – PacifiCorp (Hank LuBean – WECC OTS)
The Reset Period of this Standard is “One-calendar year.” R1.2 should be modified from “five days per year” to “five days per calendar year” to be more specific.

PER-003-0 — Operating Personnel Credentials

Brandian – ISO-NE
Associated Measure, Compliance Monitoring Process and Levels of Non Compliance are missing and needs to be defined in this standard simultaneously. Existing P6T1 outlines the levels of non-compliance.

Brandian – ISO-NE
Clarification from the Drafting Team on the intended meaning of "current" in the Measures.

David Carlson – NERC PCGC
R1 - Suggestion to be incorporated into the next version (version 1): The operating position is to be filled by a person holding the appropriate level certification. For Example; a person that is acting as the Reliability Coordiator will need to hold a Reliability Coordinator Operator Certification and a person acting as a Transmission Operator would need to hold a Transmission Operator Certification.

Doug Hils – Cinergy
R1 - Policy 8C Standard 1 is satisfactorily represented by Standard 032 Requirement 1. However, their was a one word change from "both" to "either", that can change the meaning of the statement, depending upon interpretation. In the interest of keeping the continuity between Policy 8C and Standard 32, the wording should be kept consistant and any changes be make through the normal process as part of version 1.

Doug Hils – Cinergy
R1 - Suggestion to be incorporated into the next version (version 1): The operating position is to be filled by a person holding the appropriate level certification. For Example; a person that is acting as the Reliability Coordiator will need to hold a Reliability Coordinator Operator Certification and a person acting as a Transmission Operator would need to hold a Transmission Operator Certification.

John Blazekovich – Exelon
R1 - Exelon Corporation suggests that Version 1 of this Standard be initiated to address the requirement to have NERC Certified Operators that perform functions that are formally delegated similar to the requirement of Policy 9B Req. 3.

Paul Rocha – CenterPoint
R1 - Policy 8C Standard 1 is satisfactorily represented by Standard 032 Requirement 1. However, their was a one word change from "both" to "either", that can change the meaning of the statement, depending upon interpretation. In the interest of keeping the continuity between Policy 8C and Standard 32, the wording should be kept consistant and any changes be make through the normal process as part of version 1.

Paul Rocha – CenterPoint
R1 - Suggestion to be incorporated into the next version (version 1): The operating position is to be filled by a person holding the appropriate level certification. For Example; a person that is acting as the Reliability Coordiator will need to hold a Reliability Coordinator Operator Certification and a person acting as a Transmission Operator would need to hold a Transmission Operator Certification.

Travis Bessier – TXU
R1 - The original Policy language stated that NERC-certified staffing should occur for positions that meet both criteria while changing the Version 0 Standard to say "either" changes the intent of the original policy. TXU Electric Delivery proposes that the Version 0 require meeting both criteria and any changes should be taken up with the development of Version 1.

Mike Kormos – PJM (PSE&G)
Measure could be that one has documentation of Certification of all personnel.

Hank LuBean – WECC OTS
M1.a indicates that “Trainees may perform critical tasks only under the direct, continuous supervision and observation . . .“What constitutes a “critical task?” What duties performed in a typical control center are not “critical?” Inclusion of “critical tasks” is most likely a reference to the Critical Task List that has been established to guide operators in determining which of the four certification credentials (BIO, TO, BIT, RO) they are required to attain.
The OTS suggests the reference to “critical tasks” be removed to prevent possible interpretation that the uncertified operator can perform routine tasks but not “critical” tasks. Or, change it to reference the Critical Task List of the credential and include it in the Standard.

Hank LuBean – WECC OTS
COMPLIANCE MONITORING PROCESS - It isn’t clear what is meant by “previous calendar year staffing plan.” A “staffing plan” sounds like a plan for staffing – if so, what does that have to do with filling operating positions with certified operators? A simple determination of which positions require certified operators should be sufficient. Need to modify to be clear.

PER-004-0 — Reliability Coordination – Staffing

Hank LuBean – WECC OTS
Comment – Why are Measures, Compliance Monitoring, and Levels of Non-Compliance still "Not Specified?" This is Draft 2 of the Version 0 Standards and it is expected the Standards would be fully developed by now in order for the industry to comment. What are the issues causing these parts of the Standard to remain not specified?

Hank LuBean – WECC OTS
However, Standard 36 doesn't make the same change when it states the requirement is "in addition to other training required." Why the difference? The OTS believes the RCs should be required to have a training program as stated in our comments on Standard 31, and does not see any reason to include the "in addition to other training requirements" for the RCs.

Hank LuBean – WECC OTS
Standard 31 has a Reset Period of "One-calendar year" for this requirement and OTS suggested a slight change in the language. The Compliance Monitoring Process for Standard 36 indicates "Not Specified." The OTS recommends the Reset Period be defined and include the same modification as in Standard 31, that "five days per year" be changed to "five days per calendar year."

PRC-001-0 — System Protection Coordination

Narinder Saini – Entergy
How would a Generator Operator know if a relay failure or equipment failure would reduce system reliability (isn't that the responsibility of the Transmission Operator and Reliability Coordinator). This could lead to Generator Operators not informing the Transmission Operator and Reliability Coordinator of relay or equipment failure because they did not think it mattered.

Peter Henderson – IMO (Guy Zito – NPCC CP65) (Chris de Graffenried – NYPA) (Ralph Rufrano – NYPA)
R5 refers to neighboring TOs while other sections refer to affected TOs. There is a need to use the same phrase in all sections of standards for purposes of consistency.

Guy Zito – NPCC CP73 (Chris de Graffenried – NYPA) (Ralph Rufrano – NYPA)
Many of the guides in Policy 4D are in fact criterion that are not included in this std. We are of the opinion that any critical/ criteria needs to incorporated in future via urgent SAR process. The remaining should be mapped into an version 0 accompanying Reference Document.

Chris de Graffenried – NYPA (Ralph Rufrano – NYPA)
R6 - Delete the word- all.

Roman Carter – Southern Co.
It may not be perfectly clear to the Generator Operator if a protective relay or equipment failure will reduce "system" reliability. The Transmission Operator and Reliability Coordinator need to define the scope of failures to the Generator Operator that will impact "system" reliability.

PRC-002-0 — Define and Document Disturbance Monitoring Equipment Requirements

SPP
Standard 057 - I.F.M1 should be revised because it does have enough specificity in equipment requirements. Standard 057 - I.F.M5 should be deleted from Version 0 because it shifts the burden from the Region to the members.

Raj Rana AEP
This section needs to be revised. Its deficiencies have been identified by the NERC Interconnection Dynemics Working Group (IDWG). IDWG can help in revising this section. (Reference: IDWG Report to NERC Planning Committee (PC) at PC's 7/20/04 Meeting.)

PSE&G
Add digital inputs for breaker operation, etc. for sequence of events, harmonics for large HVDC installations, and sequence currents.

PSE&G
Add load to applicable installation requirements

PRC-003-0 — Regional Procedure for Transmission Protection System Misoperations

NIPSCO
The "shall have evidence" phrase is vague and may be unnecessary considering that the requesting entity should know if its requested information is supplied.

Kirit Shah, Ameren
Change 'monitoring' to 'reporting'. It would be difficult to monitor all facilities, the SDT could expect reporting of events.
Also for R1.1 item 'a'; Measure 1.1

PRC-004-0 — Analysis and Reporting of Transmission Protection System Misoperations

Charles Matessa, BG&E
Levels of Non-Compliance - The graduated levels of UFLS are too small. Suggest: Level 1 - ok as presented. Level 2 - N/A Level 3 - Less than 100% of amount of needed load shedding capability is provided. Level 4 - Less than 90% of amount of needed load shedding capability is provided.

John Blazekovich, Exelon
Exelon Corporation suggests that Standard 067 be moved quickly to Version 1 in order to clarify levels of non-compliance. As written it appears that an entity is in compliance if it has any value greater than 95% of the regional requirements in any of the load steps.

Vinod Kotecha - Con Edison Company of New York CEPD
Norman Mah - Con Edison Company of New York CEPD
Edwin Thompson - Con Edison
Rebecca Adrienne Craft - Con Edison Company of New York CEPD
R1 : Remove the word “all”.

PRC-005-0 — Transmission Protection System Maintenance and Testing

Bob Millard, MAIN
This section should not move forward in Version 0. More procedure/data oriented, not really stand alone "standard" material but more tools or reference material for executing a standard

Ed Davis Entergy
R3-1.a – should breakers and switches be included in the list?

Ed Davis Entergy
M3-2 – what kind of evidence?

NIPSCO
M3-2 The "shall have evidence" phrase is vague and may be unnecessary considering that the requesting entity should know if its requested information is supplied.

PRC-006-0 — Development and Documentation of Regional UFLS Programs

Bob Millard, MAIN
This section should not move forward in Version 0 since it is more procedure/data oriented, not really stand alone "standard" material but more tools or reference material for executing a standard.

Ed Davis, Entergy
Compliance Monitoring Process should include that the data to be provided to Compliance Monitor – it is not clear who and to whom the data will be provided (within 30 days) on request. This is applicable to all sections.

NIPSCO
M1-2, M1-3 The "shall have evidence" phrase is vague and may be unnecessary considering that the requesting entity should know if its requested information is supplied.

PRC-007-0 — Assuring Consistency with Regional UFLS Program Requirements

Ed Davis, Entergy
Section 2 should refer to coordination of under frequency load shedding programs with those of Reliability Authority.

John Blazekovich, Exelon
Exelon Corporation suggests that Standard 067 be moved quickly to Version 1 in order to clarify levels of non-compliance. As written it appears that an entity is in compliance if it has any value greater than 95% of the regional requirements in any of the load steps.

Charles Matessa, BG&E
Levels of Non-Compliance - The graduated levels of UFLS are too small. Suggest: Level 1 - ok as presented. Level 2 - N/A Level 3 - Less than 100% of amount of needed load shedding capability is provided. Level 4 - Less than 90% of amount of needed load shedding capability is provided.

PRC-008-0 — Assuring Consistency with Regional UFLS Program Requirements

Dave Angell, WECC Relay WG
The language for protection system maintenance and testing programs should be consistant from standard to standard. The requirement in this standard should match Standard 063, Requirement R3-1. This will provide a consistent reporting requirement for all protection system.
From standard 063.3: The Transmission Owner, Generator Owner and Distribution Provider that owns a transmission protection system shall have a transmission protection system maintenance and testing program in place. The program(s) shall include:
From Standard 067.3: The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall have a UFLS equipment maintenance and testing program in place. This UFLS equipment maintenance and testing program shall include UFLS equipment identification, the schedule for UFLS equipment testing, and the schedule for UFLS equipment maintenance.

NIPSCO
The "shall have evidence" phrase is vague and may be unnecessary considering that the requesting entity should know if its requested information is supplied.

PRC-009-0 — UFLS Performance Following an Underfrequency Event

NIPSCO
The "shall have evidence" phrase is vague and may be unnecessary considering that the requesting entity should know if its requested information is supplied.

Ed Davis, Entergy
Compliance Monitoring Process requires analysis to be provided on request 90 days after the system event – it is consistent with the original standards but needs clarification. Is it on request, or mandatory to provide the data within 90 days after the event? Since this standard requires analysis and documentation of under frequency load shedding performance to be done, we suggest that the data should be provided to the Compliance monitor within 90 days of the event.

Vinod Kotecha - Con Edison Company of New York CEPD
Norman Mah - Con Edison Company of New York CEPD
Edwin Thompson - Con Edison
Rebecca Adrienne Craft - Con Edison Company of New York CEPD
UVLS : Under voltage load shedding should not be a requirement for all parties. Those who have shunt reactors can meet the objective by not shedding load but by shedding shunt reactors. Flexibility in achieving the desired goal is appropriate.

PRC-010-0 — Assessment of the Design and Effectiveness of UVLS Program

NIPSCO
The "shall have evidence" phrase is vague and may be unnecessary considering that the requesting entity should know if its requested information is supplied.

MAPP Planning Standards Subcommittee
The Level 4 compliance requirements should have "the technical assessment provided but not complete language" moved to Level 1.

Thomas Mielnik, MAPP PSDWG
In Non-Compliance Level 4, clarify what one of the requirements means. MAPP PSDWG prefers breaking this level into two levels of non-compliance.

Vinod Kotecha - Con Edison Company of New York CEPD
Norman Mah - Con Edison Company of New York CEPD
Edwin Thompson - Con Edison
Rebecca Adrienne Craft - Con Edison Company of New York CEPD
UVLS : Under voltage load shedding should not be a requirement for all parties. Those who have shunt reactors can meet the objective by not shedding load but by shedding shunt reactors. Flexibility in achieving the desired goal is appropriate.

PRC-011-0 — UVLS System Maintenance and Testing

NIPSCO
The "shall have evidence" phrase is vague and may be unnecessary considering that the requesting entity should know if its requested information is supplied.

Vinod Kotecha - Con Edison Company of New York CEPD
Norman Mah - Con Edison Company of New York CEPD
Edwin Thompson - Con Edison
Rebecca Adrienne Craft - Con Edison Company of New York CEPD
UVLS : Under voltage load shedding should not be a requirement for all parties. Those who have shunt reactors can meet the objective by not shedding load but by shedding shunt reactors. Flexibility in achieving the desired goal is appropriate.

PRC-012-0 — Special Protection System Review Procedure

Ed Davis, Entergy
Requirements of Section 1 should refer to Reliability Authority rather than Regional Reliability Councils.

Peter Henderson, IMO
As currently stated, the levels of non-compliance are not selective. Some of the items listed in R1-1 are more critical than others. Missing R1-1 c is not the same as missing R1-1 h.

PRC-013-0 — Special Protection System Database

Bob Millard, MAIN
This section should not move forward in Version 0 since it is more procedure/data oriented, not really stand alone "standard" material but more tools or reference material for executing a standard.

NIPSCO
The "shall have evidence" phrase is vague and may be unnecessary considering that the requesting entity should know if its requested information is supplied.

PRC-014-0 — Special Protection System Assessment

Bob Millard, MAIN
This section should not move forward in Version 0 since it is essentially already covered by Version 0 STD 051.

Bill Bojorquez, ERCOT
The Transmission Planner or Operator, not the Regional Reliability Council, should perform the assessments of the operation, coordination, and effectiveness of Special Protection System installed in their service territory. The RRC could gather, review, and summarize such assessments.

Ed Davis, Entergy
Section 3 refers to Regional Reliability Council for assessing the operation, coordination, and effectiveness of all Special Protection System. Reliability Authority or other entities included in the Functional Model should have this responsibility.

PRC-015-0 — Special Protection System Data and Documentation

Bob Millard, MAIN
This section should not move forward in Version 0 since it is essentially already covered by Version 0 STD 051.

NIPSCO
M4-3 The "shall have evidence" phrase is vague and may be unnecessary considering that the requesting entity should know if its requested information is supplied.

PRC-016-0 — Special Protection System Misoperation

Bob Millard MAIN
This section should not move forward in Version 0 since it is more procedure/data oriented, not really stand alone "standard" material but more tools or reference material for executing a standard.

MAPP Planning Standards Subcommittee
R5-1 - Change 3rd line to " . . . shall analyse it's Special Protection System misoperations in accordance with . . . ".

John Blazekovich, Exelon
Exelon Corporation suggests that Standard 069 be moved quickly to Version 1 in order to re-write R5-2 to state that that a TO, GO or DP need only have evidence that action was taken to avoid misoperations after having had one. Further we feel that SPS requires a more clear definition of what types of protection system fall into the "SPS" (e.g. automatic load throwover systems).

NIPSCO
The "shall have evidence" phrase is vague and may be unnecessary considering that the requesting entity should know if its requested information is supplied.

PRC-017-0 — Special Protection System Maintenance and Testing

Ed Riley, CA-ISO
In f, it needs to be changed to require that the last two dates of testing and maintenance are kept. This is necessary to verify an action that is required bi-annually or bi-monthly.

NIPSCO
The "shall have evidence" phrase is vague and may be unnecessary considering that the requesting entity should know if its requested information is supplied.

TOP-001-0 — Reliability Responsibilities and Authorities

Michael Moltane - ECAR
General Comment: Need good, clear definition of "Reliability Emergency" for this to work. Otherwise we will get into the endless and age-old discussion of "what is an emergency?".

Roman Carter – Southern Co.
1 - This req. states "The RA, BA, and TO shall have the responsibility…". The original language in Policy 5 for this requirement uses Operating Authority and this includes entities such as the GO, TO, and BA but not the Reliability Coordinator. Throughout this V-0 Standard the RA is subsituted for the RC even within this requirement. Since the original policy says RCs are excluded, this poses a conflict for this requirement. This is also in Req's 2,4,5.

Michael Moltane - ECAR
R1: Recommend adding wording to the sentence "clear decision making authority" that such authority should be documented and incorporated into Operating Procedures so that there will not be any confusion in real time emergencies as to who is responsible for what, and to whom.

Alan Boesch – NPPD
R2 - The Functional Model says the Balancing Authority "Implements emergency procedures as directed by the Reliability Authority". Please change to requirement or revise the functional model.

Southern Company
R4 and R6 - Should specify that the local RA will handle all communications with other potentially impacted Reliability Coordinators. As written (Reliability Authority or …), these requirements could lead to multiple notifications and potential confusion as to exactly what action is going to happen or has taken place. In general, all communications with adjacent Reliability Authorities should be through the local Reliability Coordinator. (Note that R4 may intend that RA contact other RAs, etc., but this is not clear and could easily be misinterpreted.)

Peter Henderson – IMO (Guy Zito – NPCC CP9) (Chris de Graffenried- NYPA) (Ralph Rufrano – NYPA)
In the sentence: "Under these circumstances the Transmission Operator or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive …" The use of "or" is confusing and may create ambiguity. The specific role of entity responsible for 'providing' and 'receiving' information needs to be clarified. Should this be combined responsibility applicable to all or for any?
**For the purposes of effective implementation/enforcement of these standards, we recommended that the associated measures, compliance monitoring process and levels of non compliance should also be (a) simultaneously mapped/specified where these exist already and (b) specifed/addressed in the very near future, where these do not exist today for consistency.
**This comment also applies to Standards 19, 21, 26, 34 and 35.

Roman Carter – Southern Co.
There are times when a Generator Operator must act quickly and may not have time to notify the Transmission Operator. There needs to be an exception here (like that listed in 7C for the RA and TOP) for emergency situations that allows follow up notification by the GO.

TOP-002-0 — Normal Operations Planning

Alan Johnson – Mirant
Concerned that the translation from Control Area to BA or TOP creates a new requirement for the GOP. The proposed language allows the possibility of the GOP having to perform tests at the request of both the BA and TOP. The GOP should only be required to perform 2 seasonal capability tests per year (winter and summer) within pre-defined parameters.

Southern Company
General - Hierarchical structure seems to be implied, but not explicitly defined in the translation of Control Area and Reliability Coordinator language to functional model language. May want to consider writing requirements such that all Balancing Authorities and Transmission Operators within a given Reliability Authority's area should coordinate their operations planning, etc.

PG&E
R3, R4, R5 - The parentheticals "where confidentiality agreements allow" imply that confidentiality agreements trump coordination of operational plans needed to assure system reliability. They should be eliminated.

Reliability Authorities would then be responsible for coordination between each other, etc. Seems confusing and/or difficult to follow as written.

Roman Carter – Southern Co.
4, 5 - Requirement says LSE, TSP, and GO coordinate with BA (where confidentiality agreements allow). Under the F.M., the BA can delegate certain tasks that prevent the BA from meeting the Conf. Agreement in order for the BA to meet the obligations of the BA. Version-0 Standard should recognize this ability.

Roman Carter – Southern Co.
Requirement states without intentional delay. How is this enforceable? The burden of proof is with the enforcement organization.

Ray Morella - FirstEnergy
R7 - Need to explicitly and preciselydefine what N-1 contingency means.

Raj Rana – AEP
R18 - R18 only needs to state that the BALANCING AUTHORITIES shall,
without any intentional time delay, communicate the information
described in the requirement R15 above to their RELIABILITY
AUTHORITY, or add such statement to R15. R17 already requires notification to the RA, and these were the activities that Policy today requires notification to the RA, as referenced in Policy 6A R6.1 - 6.5.

Peter Lebro – National Grid
R3, R4, R5, R12, R17: Confidentiality of information should not be a factor when it comes to reliability – this needs to be addressed otherwise Companies may hide behind the confidentiality clause and not provide the data necessary to conduct operational reliability assessments and coordinate reliable operations.

TOP-003-0 — Planned Outage Coordination

Peter Lebro – National Grid
Standard 16:R1, Standard 37:R4: In the standards it states outage data (generation and transmission) is only required to be submitted by noon of the day ahead, the emphasis should be on submitting the data as soon as it is known but no later that noon day ahead.

Anita Lee - AESO
CMP - Third paragraph - The RA should "direct" the cancellation of an outage, not "request".

Robert Snow
Outage information is needed by neighboring reliability authorities much sooner than one day pror to the outage.

TOP-004-0 — Transmission Security

Brandian – ISO-NE (Guy Zito – NPCC) (Pete Henderson – IMO)
In the existing policy the overall role of monitoring of SOL or IROL was assigned to a Control Area. In the applicable version 0 standards a clarification on the role and relationship between Reliability Authority and Transmission Operator should be made with regards to the monitoring of SOL & IROL.

Guy Zito – NPCC
These Standards must clearly identify, define and provide examples of what a SOL and IROL are. The reason for this is that this is not consistently interpreted by industry.

Robert Snow
Transmission Security during operation should conform to the applicable portions of Table 1 in the planning standards.

Vinod Kotecha - Con Edison Company of New York CEPD
Norman Mah - Con Edison Company of New York CEPD
Edwin Thompson - Con Edison
Rebecca Adrienne Craft - Con Edison Company of New York CEPD
There remains vagueness in the application of Interconnection Reliability Operating Limits (IROL) and guidelines for how it is calculated. The RC has been designated as being responsible for maintaining the interconnection within IROLs, however debate on how these should be calculated continues.

Michel Armstrong - Hydro-Quebec HQT
There remains vagueness in the application of Interconnection Reliability Operating Limits (IROL) and guidelines for how it is calculated

Michael Schiavone - Niagara Mohawk
There remains vagueness in the application of Interconnection Reliability Operating Limits (IROL) and guidelines for how it is calculated. The RC has been designated as being responsible for maintaining the interconnection within IROLs, however debate on how these should be calculated continues.

NYSRC – Alan Adamson
There remains vagueness in the application of Interconnection Reliability Operating Limits (IROL) and guidelines for how it is calculated. Therefore, debate continues on how IROL should be calculated. We urge that future revisions of Version 0 will address this issue.

LIPA – Richard Bolbrock
There is vagueness in the application of IROL limits -- keep as is but revise in future standard revisions.

Tracy Edwards - BPA-TBL
R5 indicates that every effort shall be made to remain connected to the Interconnection. However the second sentence of the requirement implies that it may be acceptable to disconnect from the Interconnection if there is imminent danger of violating an IROL or SOL. There can be other conditions other than violating IROL's or SOL's that place the system at great risk. In fact, violating an IROL or SOL in itself does not necessary mean the system is at

imminent risk.   Therefore, change the second sentence of R5 to read as follows: The Reliability Authority or Transmission Operator may take such actions as disconnecting from the Interconnection, as it deems necessary, to protect its Area.

Guy Zito - NPCC CP17 (Chris de Graffenried – NYPA)
(Also in R5) This needs to be clarified whether these requirements have to be fulfilled by both presently worded RA (i.e. new proposed terminology RC) and TO - “individually or jointly”. It is not clear that who would be overall monitor. A more clear role needs to be identified in this standard. Also Reliability entity should be termed as ‘RC’. Please see comments in Q1.

Roman Carter – Southern Co.
It is not practical to say the RA and the TOP operate, when practical, to protect against instability, separation, or cascading outages. Recommend removing "when practical" because when is it ever practical to allow cascading outages.

TOP-005-0 — Operational Reliability Information

Brandian – ISO-NE (Guy Zito – NPCC) (Pete Henderson – IMO)
Applicability - Add Generator Owners and Load Serving Entities. Extend R5 to include these Functional Model entities.

Ed Riley – CAISO
R1 - Current policy is for data to be updated every 10 minutes, and is in Standard 15. This rate is too slow and should be increased (every 4-10 seconds) when possible. This should be addressed in Version 1.

Robert Snow
In Attachment 1, the generator data should include status of voltage control and power system stabilizer facilities.

Tracy Edwards - BPA-TBL
Attachment 015-1: Need a time frame for this data, it is not measurable as it reads now.

Peter Lebro - National Grid
National Grid USA would like to make the following recommendations to be considered when drafting the next draft of Version 0. Standard 15: There should be a requirement on generators to provide the necessary data as there is a requirement on the PSE's (R6), a paragraph R7 should be inserted which reads 'Generation Operators shall provide information requested by their host Balancing Authority and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.'

TOP-006-0 — Monitoring System Conditions

Guy Zito – NPCC
Associated Measure, Compliance Monitoring Process and Levels of Non Compliance are missing and needs to be defined in this standard simultaneously.

Michael Moltane – ECAR
R1.1: Should clarify that the the Gen Operator needs to provide “normal and emergency capability for use”, as opposed to current wording of just “.all generation resources available for use” (i.e., stretch capability, maximum run time for emergency capability, etc.).
R7: Indicates that entities shall “monitor system frequency”……recommend adding wording to indicate frequency shall monitor system frequency at multiple points on their system.

Alan Boesch – NPPD
R4 - In the Functional Model load forecasts are developed by the Load Serving Entity and provided to the Balancing Authority. The BA sends the agregated information to the RA. The TOP is not involved in this process. Please change the requirement to match the functional model.

Eric Grant – Progress Florida (Phil Creech – Progress)
R4 - Load forecasting is the starting point for planning capacity for obligations and thus, deemed to be required for reliability.

Travis Bessier
TXU
R4 – In answer to the question under “Comments”, load forecasting is required for reliability. For example, with forecast load information, potential overloaded facilities can be identified given expected transmission configuration when evaluating future grid operating requirements.

PG&E
R4 - Load Forecasts are essential for reliable system operations and form the foundation for operational planning.

FRCC
Drafting Team Comments - R4 - The Drafting Team asked the following: Is load forecasting required for reliability or not, if not, why is this information required? We believe that load forecasting is required to determine SOLs or IROLs. If load is known, the Operations Planning process will identify actions required to eliminate or mitigate potential reliability issues.

Gerald Reahlt – Manitoba
Load forecasting is required for reliability as there is a need to predict possible shortages due to high loads.

TOP-007-0 — Reporting SOL and IROL Violations

Ed Riley – CAISO
Measures - 2nd paragraph should be changed to read "…within IROL or SOL…" The CAISO believes that suggesting that the determination of an SOL becoming an IROL after the fact is inappropriate.

Eric Grant, Phil Creech – Progress
R1-R5 - In general, unless better bounds/criteria are set for the determination of IROLs, this standard will not be enforceable or auditable.

Phil Creech – Progress
"Applicability" for this standard should include "Reliability Authorities"

Gerald Reahlt – Manitoba
R5 - This should be considered as a compliance monitoring or administrative procedure rather than a standard.

FRCC
R5 Drafting Team Comment - The Drafting Team stated that R5 should be considered as a compliance monitoring or administrative procedure rather than a standard. We agree, and during the transition from Version 0 Standards to Version 1 Standards these types of changes will be addressed. In addition, these types of administrative issues will need to be consistent with the approved NERC Disclosure Guidelines.

Martin Huang – BC Transmission
R1 and M1 both requires the Reliability Coordinate be informed of any IROL or SOL violation but the level of non-compliance only applies when the limit is exceeded more than 30 minutes and none for failure to report the violation.

Tracy Edwards - BPA-TBL
Compliance Monitoring Process: (bullets following the first paragraph) 2) … Is vague and not measureable 3) … Would not nessarly make it an IROL. 4) … Would not nessarly make it an IROL. 5) … Is vague and there is no unacceptable loss of load definition for NERC that is measurable

Tracy Edwards - BPA-TBL
Compliance Monitoring Process: (first paragraph, second sentence) If this sentence were true the violation would have been an IROL to begin with. Give an example of this scenerio.

Tracy Edwards - BPA-TBL
Give an example of how you would show evidence something was evaluated. This does not seem like a possible measure. Also the RC may not have needed to give any additional direction and would therefore not have any evidence as required by the measure.

Linda Campbell – FRCC
Standard 008, M1-M3. What kind of evidence is anticipated? The word evidence can be very subjective and broad. Also the RA should be removed from these measures.

TOP-008-0 — Response to Transmission Limit Violations

- No V1 comments

TPL-001-0 — System Performance Assessments Under Normal Conditions

Terry Bilke, MISO
It appears that the existing label heading “System Study/Testing Methods” should be prefixed with “R1-2” to read as follows:
“R1-2 System Study/Testing Methods”
Then re-number the subsequent R1-“n” headings one number higher than they are presently numbered.
Under this newly corrected heading “Standard 051 R1-2 System Study/Testing Methods” reword item 5. The purpose of the rewording is to meet the current intent, but improve the current wording. The current wording implies that there is never a conflict with modeling projected firm transfers. Firm transfers in the planning horizon based on confirmed Transmission Service Reservations and Network Service to not translate to a unique set of transfers that can be modeled. The changed wording allows disallowing impossible simultaneous use of Firm reservations in creating the mode by leaving out the word “all” and adding some qualifying words. The revised wording also provides the key instructional words needed to create the intended model from a market-based environment versus the current confirmed Firm Transmission Service set of information. This should help clarify how to achieve the intended notion of modeling just the firm transfers.
Replace:
Have all projected firm transfers modeled.
With:
Have projected firm transfers modeled (includes all firm transfers that are simultaneously possible).
Or also affect a market-based notion of firm transfers by replacing with:
Have projected firm transfers modeled (includes all firm transfers that are simultaneously possible). Or similarly in a central dispatched or market based environment, model simultaneously possible firm bi-lateral contracts and model a dispatch of the system with a high hurtle rate so as to mitigate the creation of a constrained base case model.

MAPP Planning Standards Subcommittee
R1-1 - "4. Address any planned upgrades needed to meet the performance requirements of Category A." is vague. Replaced "Address" with "Provide the status of".

Gerald Reahlt, Manitoba
The Standards should clarify the timing for the corrective plan. Whan an assessment study finds that the system is not able to meet the performance requirements, a corrective plan is required. Normally, development of mitigation plans requires subsequent studies, and may actually be done by a different entity than the entity performing the assessment (the TO instead of the RTO who may have done the assessment). A written summary of plans is required. The SDT must clarify if the written summary of mitigation plans is part of the assessement report or not. MH believes that it should be a separate document, and addressed as such in the cpmpliance section.

Charles Matessa, BG&E
Table 1 – Note a - Please clarify that applicalbe ratings pertaining to emergency short durations are only applicable to thermal ratings, and not voltage limits. In the first sentence voltage limits are included in the applicable rating definition but there is no distinction made in the second sentence for short term thermal limits versus short term voltage limits which in our opinion should not apply.

PSE&G
Table 1: Should address deliverability of generation to load

Roman Carter, Southern
Marc Butts, Southern
It should be made clear that the requirement to deliver generator unit output to meet projected customer demand in R1-1 should be for those generator units with firm deliverability, even to native load customers. Without designation of the capacity and granting of firm service, it should not be a requirement to build transmission for speculative sources of native load generation.

Kirit Shah, Ameren
(applies to Standards 051.1, 051.2, 051.3, 051.4)
It is assumed that the term "critical system conditions" applies to the season of the year and assumed load level (peak, minimum, etc.), and not the state of the transmission system. The latter assumption would be particularly contradictory for Standard 051.1 which is to consider the system with no contingencies.

Kirit Shah, Ameren
Having all projected firm transfers modeled may not be practical to achieve in a single shapshot of a powerflow model. The requirement should allow engineering judgment to determine the appropriate level of system utilization to assess reliability considering all projected firm uses. We assume that the phrase "firm transfers" in the Standards refers to both capacity-backed transactions as well as transmission service reservations. Traditionally, capacity-backed transaction values are supported by contracts and are agreed to between entities prior to the development of the powerflow models. Transmission service reservations are more volatile and may be firm on one system, but not on another. Reservations may have been secured for reasons other than to support capacity transactions, they may be held for other specific system needs or as options to meet dynamic market conditions. Because of the nature of the transmission service reservations, it is inappropriate to model all firm transmission service reservations at the same time, as these reservations will not all go to schedule at the same time. For example, some generators have reserved 100% of their plant output in multiple directions to provide for flexibility to deliver to more than one customer or direction, but not more than 100% of the full plant output at the same time. Vertically integrated utilities have reservations going out as well as coming in, to provide for both export opportunities for their generation and to cover import conditions to ensure reliability to their load. Blindly including all transmission reservations in the powerflow models (in, out, and through) would overstate the loading on key facilities in some areas or introduce counterflow, which would understate and mask the loading problems on key facilities in other areas. It is also very difficult to model and glean meaningful results. Therefore, it is suggested that reservations be reviewed for "polarity", as they can increase or decrease the loading on key facilities. Including the word "projected" in the detailed bullet allows some amount of engineering judgment and subjectivity to enter into the modeling assumptions, but this idea needs to be expanded to ensure that they are applied consistently throughout the industry. More than one set of reservations needs to be reviewed to adequately consider the impact of transmission service reservations.

Kirit Shah, Ameren
The requirements of the standards refer to "all demand levels over a range of forecast system demands", yet the detailed bullet mentions that the studies should "be performed for selected demand levels". While we agree that studies are not necessary for all demand levels, more than

a single demand level is required for assessment to adequately demonstrate that the load range is covered. This idea needs to be included for clarity.

Al DiCaprio, MAAC
Item c, the 8th bullet references Planned facilities for inclusion of studies. Does the SDT envision inclusion of all 'proposed' Planned facilities or do they envision just the ones under-constructuion? Or do they envsion some other definition of planned facilities?

Linda Campbell, FRCC
Standard 051.1, R1-2 Instead of stating….provide written summary, state develop since R1-3 tells to provide it to the compliance monitor. This same comment applies to 051.2, R2-2 and 051.3, R2-3.

Kirit Shah, Ameren
Entities (Transmission Providers) responsible for selling/allocating/approving transmission service need to include in their assessments the issues described in item number 3 above to ensure that the transmission system is not oversubscribed and that there are no reliability concerns associated with existing and future transmission service sales. Granting more firm transmission service assuming conterflow will be there would degrade system reliability.

Robert Snow, Independent Contributor
Return to the requirement for multiple time frame studies without exception. If the studies are not conducted, one will never really know if ther is a marginal condition.

Charles Matessa, BG&E
Table 1 - Note a) Please clarify that applicalbe ratings pertaining to emergency short durations are only applicable to thermal ratings, and not voltage limits. In the first sentence voltage limits are included in the applicable rating definition but there is no distinction made in the second sentence for short term thermal limits versus short term voltage limits which in our opinion should not apply.

PSE&G
Table 1: Should address deliverability of generation to load

Vinod Kotecha - Con Edison Company of New York CEPD
Norman Mah - Con Edison Company of New York CEPD
Edwin Thompson - Con Edison
Rebecca Adrienne Craft - Con Edison Company of New York CEPD
Table 1 D Item 11 - Remove “major Load center” because it’s not clear as to what constitutes a major load center”.

Edwin Thompson - Con Edison
Rebecca Adrienne Craft - Con Edison Company of New York
Table 1 - Item C 5. The table is not clear and goes beyond the present double circuit outage criteria. It needs to be changed to state " Two adjacent circuits of a multiple circuit towerline" instead of "Any two circuits of a multiple circuit towerline".

Edwin Thompson - Con Edison
Rebecca Adrienne Craft - Con Edison Company of New York
CEPDTable 1 Items 6, 7, 8, and 9 need to have a footnote that states that they do not apply to generator breaker failure conditions.

Edwin Thompson - Con Edison
Rebecca Adrienne Craft - Con Edison Company of New York
Table 1 Footnote b last sentence states : "To prepare for the next contingency, system adjustments are permitted, including curtailment of contracted Firm electric power transfers". The issue here is "should you curtail firm deliveries ahead of time or should you curtail them only after a contingency occurs"?

TPL-002-0 — System Performance Following Loss of a Single BES Element

Kirit Shah, Ameren
(applies to Standards 051.1, 051.2, 051.3, 051.4)
It is assumed that the term "critical system conditions" applies to the season of the year and assumed load level (peak, minimum, etc.), and not the state of the transmission system. The latter assumption would be particularly contradictory for Standard 051.1 which is to consider the system with no contingencies.

Gerald Rhealt, Manitoba Hydro
The Standards should clarify the timing for the corrective plan. Whan an assessment study finds that the system is not able to meet the performance requirements, a corrective plan is required. Normally, development of mitigation plans requires subsequent studies, and may actually be done by a different entity than the entity performing the assessment (the TO instead of the RTO who may have done the assessment). A written summary of plans is required. The SDT must clarify if the written summary of mitigation plans is part of the assessement report or not. MH believes that it should be a separate document, and addressed as such in the cpmpliance section.

PSE&G
Similar comments as in S-1 in S-2, S- 3, and S-4 except actually call on transmission owners to provide statement of action.

Travis Bessier, TXU
Item no. 10, under subheading System Simulation Study/Testing Methods, should be changed to read: 10. Include the effects of existing and planned protection systems, including any backup, redundant, or Special Protection Systems. Add an item no. 13 as follows: 13. Include the effects of existing and planned operating procedures.

Charles Matessa, BG&E
Table 1 – Note a - Please clarify that applicalbe ratings pertaining to emergency short durations are only applicable to thermal ratings, and not voltage limits. In the first sentence voltage limits are included in the applicable rating definition but there is no distinction made in the second sentence for short term thermal limits versus short term voltage limits which in our opinion should not apply.

PSE&G
Table 1: Should address deliverability of generation to load

Kirit Shah, Ameren
Generation runback and redispatch should not be allowed to meet the performance criteria of this standard (single contingency). If generation runback is allowed, this runback amount should not be considered as "firm".

Robert Snow, Independent Contributor
Require that all contingencies be studied and then determine which are severs. Most of the August 14 outages by themselves would not have been considered severe.

Robert Snow, Independent Contributor
Perform and evaluate the performance over a level of system demands with a variety of generation dispatches.

Kirit Shah, Ameren
Regarding R2-1c) bullet 12, maintenance outages are granted in the operating horizon considering the expected demand level, generator dispatch, transmission facilities out of service, and transmission flow patterns, which should be part of a very near-term system assessment and not a longer-term planning assessment. How is this different than the Standard 051.3 assessment which is also supposed to cover all demand levels and multiple contingencies?

Thomas Mielnik, MAPP PSDWG
Delete the bullet include the planning (including maintenance) outage of any bulk electric equipment…. This is confusing. Is this asking for an exhaustive study of planned outages plus all Category B? Or is it just supposed to be add any planned outages that are known at the time the study is conducted? Or something else?

Kirit Shah, Ameren
From the description in R2-1 and Category B of Table I (column 2), it is specified that the elements to consider for contingencies include generators, transmission circuits, and transformers only. Circuit breakers by themselves are not included in this list of elements. Therefore, the outage of a single terminal or opening of a single circuit breaker of a multi-terminal transmission circuit should be an invalid outage and this standard should clearly state this.

Robert Snow, Independent Contributor
Return to the requirement for multiple time frame studies without exception. If the studies are not conducted, one will never really know if ther is a marginal condition.

TPL-003-0 — System Performance Following Loss of Two or More BES Elements

Kirit Shah, Ameren
(applies to Standards 051.1, 051.2, 051.3, 051.4)
It is assumed that the term "critical system conditions" applies to the season of the year and assumed load level (peak, minimum, etc.), and not the state of the transmission system. The latter assumption would be particularly contradictory for Standard 051.1 which is to consider the system with no contingencies.

Thomas C. Mielnik - MidAmerican Energy Company
We believe that the standards continue to have non-deal-killer issues, such as inconsistency of compliance levels, ambiguity with regard to prior planned outages for Category C events in TPL-003-0 . . .

Charles Matessa, BG&E
Table 1 – Note a - Please clarify that applicalbe ratings pertaining to emergency short durations are only applicable to thermal ratings, and not voltage limits. In the first sentence voltage limits are included in the applicable rating definition but there is no distinction made in the second sentence for short term thermal limits versus short term voltage limits which in our opinion should not apply.

PSE&G
Table 1: Should address deliverability of generation to load

Gerald Rhealt, Manitoba Hydro
The Standards should clarify the timing for the corrective plan. Whan an assessment study finds that the system is not able to meet the performance requirements, a corrective plan is required. Normally, development of mitigation plans requires subsequent studies, and may actually be done by a different entity than the entity performing the assessment (the TO instead of the RTO who may have done the assessment). A written summary of plans is required. The SDT must clarify if the written summary of mitigation plans is part of the assessement report or not. MH believes that it should be a separate document, and addressed as such in the cpmpliance section.

PSE&G
Similar comments as in S-1 in S-2, S- 3, and S-4 except actually call on transmission owners to provide statement of action.

MAPP Planning Standards Subcommittee
MAPP has numerous other comments about this standard that were provided for NERC Version 1 SAR 500. MAPP is concerned that penalties not be based upon a number of low-probability low-consequence events in Category C such as breaker or bus failure resulting in marginal local area overloads.

MAPP Planning Standards Subcommittee
Delete "12. Include the planning (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planning (including maintenance) outages are performed." Or at a minimum, qualify it to refer to "only known maintenance outages".

Kirit Shah, Ameren
see item #3 above for Standard 051.2
[3. Regarding R2-1c) bullet 12, maintenance outages are granted in the operating horizon considering the expected demand level, generator dispatch, transmission facilities out of service,
and transmission flow patterns, which should be part of a very near-term system assessment and
not a longer-term planning assessment. How is this different than the Standard 051.3 assessment
which is also supposed to cover all demand levels and multiple contingencies?]

Thomas Mielnik, MAPP PSDWG
Delete the bullet include the planning (including maintenance) outage of any bulk electric equipment…. This is confusing. Is this asking for an exhaustive study of planned outages plus all Category B? Or is it just supposed to be add any planned outages that are known at the time the study is conducted? Or something else?

Narinder Saini, Entergy
Compliance Monitoring Responsibility: Add the sentence (Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process).
Thomas Mielnik, MAPP PSDWG
Add Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process. To the Compliance Monitoring Responsibility section.

Robert Snow, Independent Contributor
If a controlled interruption of customer demand or the planned removal of generators, or the curtailment of firm power transfers is necessary, the locations, amounts and expected duration of the outages will be clearly identified in the report so that the results may be duplicated by a third party. (I do not believe this is an expansion because it has always been considered that the work could be duplicated by another professional.)

Robert Snow, Independent Contributor
Return to the requirement for multiple time frame studies without exception. If the studies are not conducted, one will never really know if ther is a marginal condition.

Kirit Shah, Ameren
see item #3 above for Standard 051.3
[3. Is it the intent of the Standard that Category C and D contingencies of Table I should be considered along with facilities out of service for maintenance at lower system demand levels? We believe that the system does not necessarily have to be designed to support multiple outages, at some prescribed off-peak load level, because maintenance outages can be be rescheduled to permit the outage at lower off-peak load levels with acceptable system performance. This rescheduling may also allow for additional thermal capability that may be available at off-peak times.]

TPL-004-0 — System Performance Following Extreme BES Events

Kirit Shah, Ameren
(applies to Standards 051.1, 051.2, 051.3, 051.4)
It is assumed that the term "critical system conditions" applies to the season of the year and assumed load level (peak, minimum, etc.), and not the state of the transmission system. The latter assumption would be particularly contradictory for Standard 051.1 which is to consider the system with no contingencies.

John Blazekovich, Exelon
Exelon Corporation suggests that Standard 051 be moved to Version 1 to address table D contingencies. We don't feel that it is necessarily appropriate to study the worst contingency since that will most likely be catastrophic. R4 is a weak standard in that no specific mitigation is required. We think that it would be better to perform an analysis on a 'credible' or 'reasoned' contingency that may be more likely, a specific concern, etc.

Charles Matessa, BG&E
Table 1 – Note a - Please clarify that applicalbe ratings pertaining to emergency short durations are only applicable to thermal ratings, and not voltage limits. In the first sentence voltage limits are included in the applicable rating definition but there is no distinction made in the second sentence for short term thermal limits versus short term voltage limits which in our opinion should not apply.

PSE&G
Table 1: Should address deliverability of generation to load

Vinod Kotecha - Con Edison Company of New York CEPD
Norman Mah - Con Edison Company of New York CEPD
Edwin Thompson - Con Edison
Rebecca Adrienne Craft - Con Edison Company of New York CEPD
R.1.3.9 : Remove from the Extreme Bulk Electric System (BES) Events because extreme contingencies should not limit maintenance or facility repairs after outage conditions.

Charles Matessa, BG&E
System Simulation Study/Testing Methods - This section refers to extreme event testing Category D). As such, there is some limited subset of extreme event conditions that are developed for study. There are many more events which are not tested, some of which are less severe and some which are more severe. It is the judgment of the Transmission Owner/Operator to determine which extreme events are required to be analyzed. This renders the explanation requirements for 1b inappropriate.

Travis Bessier, TXU
Item no. 7, under subheading System Simulation Study/Testing Methods, should be changed to read: 7. Include the effects of existing and planned protection systems, including any backup, redundant, or Special Protection Systems. Add an item no. 10 as follows: 10. Include the effects of existing and planned operating procedures.

Al DiCaprio
Item 'd' revise to : “All Categories of Contingencies (e.g. lines, transformers…)”.

Robert Snow, Independent Contributor

If a controlled interruption of customer demand or the planned removal of generators, or the curtailment of firm power transfers is necessary, the locations, amounts and expected duration of the outages will be clearly identified in the report so that the results may be duplicated by a third party. (I do not believe this is an expansion because it has always been considered that the work could be duplicated by another professional.)

TPL-005-0 — Regional and Interregional Self-Assessment Reliability Reports

Al DiCaprio
4th bullet - drop words "Fuel supply and"; or define the phrase Fuel Adequacy. NERC does not have a measure or definition of Fuel Adequacy. Fuel storage is an economic decision. Little or no storage with continuous supplies is a normal condition. Who will decide if that is 'adequate'?

Al DiCaprio
Delete "…other Regional Relaibility Organazations or …" First, measures should not introduce new requirements. There is no Requirement that permits one RRO to make a mandatory request of another RRO for any study.

TPL-006-0 — Assessment Data from Regional Reliability Organizations

- No comments for V1.

VAR-001-0 — Voltage and Reactive Control

Alan Johnson – Mirant
This requirement appears to be more of a business practice than a reliability standard.

Tracy Edwards - BPA-TBL
I'd like to expand this to include UF and Volts per Hertz protection relays as well.

Tracy Edwards - BPA-TBL
Define _voltage levels_. Clarify if this applies to Transmission only, or Transmission and Distribution.

Peter Henderson – IMO
Under "Purpose", the last sentence be read as: "To ensure voltage levels, reactive flows, and reactive resources are monitored ………………….. in real time to protect equipment and to ensure/facilitate the reliable operation of the Interconnection"

Travis Bessier – TXU
Both existing Policy and Functional Model appear deficient with respect to responsibility for voltage/reactive support. It appears that Version 0 attempts to address this somewhat. See following suggested changes.

Travis Bessier – TXU
Add Generation Owner as an entity that also provides voltage support as stated in the Functional Model. Balancing Authority is another entity that should also be added to R1.

PSE&G
A Distribution Provider needs to present a reasonable Power Factor to the transmission system.

Brandian – ISO-NE
R3 - NERC Standards should not dictate how a market works. Remove "(self-provide or provide)".

Travis Bessier – TXU
R5 - Add the Balancing Authority as in R1 & R3. Also add "as directed by Reliability Authority" to the end of R5.

Travis Bessier – TXU
R7, R8, R10, R11 - Add Reliability Authority for its role in overall reliability coordination even though existing Functional Model omits this aspect with respect to voltage/reactive support.

Deanna Phillips – BPL-PBL
To add clarity and reflect the sequencing of the actions involved, please move R9 to R5.2.

Guy Zito – NPCC (Pete Henderson – IMO)
Measures - Associated Measure, Compliance Monitoring Process and Levels of Non Compliance are missing and needs to be defined in this standard simultaneously

Raj Rana – AEP

The 30-minute action time does not apply to SOL violations unless those violations have become IROL violations. The reference to SOL violations should be deleted.

Tracy Edwards - BPA-TBL
Reactive resourses that cover _first contingency_ only sounds incomplete. It should cover first contingencies and multiple contingencies where these have a high probability of occurring. The term _high probability_ would then be defined.

Peter Henderson – IMO
Under "Measures", "Compliance Monitoring Process" and "Levels of Non-Compliance", there is a lack of a clear and consistent compliance process. While the standards and requirements are mentioned in all standards, yet in many of the standards the associated Measures, Compliance Monitoring Process and Levels of Non Compliance are missing or not specified.