Agenda Draft
Planning Committee
March 3, 2020 | 1:00 – 5:00 p.m. Eastern
March 4, 2020 | 8:00 a.m. – 12:00p.m. Eastern

Welcome and Introductions

NERC Antitrust Compliance Guidelines, Participant Conduct Policy, and Public Announcement

Agenda

1. Remarks and Reports
   a. Leadership Report – Brian Evans-Mongeon (chair) and Joe Sowell (vice-chair)
      i. February Board of Trustees Meeting Update
      ii. PC working group leadership changes (if any)

2. Consent Agenda
   a. December 10-11, 2019 Meeting Minutes – Approve
   b. SAR for Applicability of Transmission-Connected Reactive Devices in NERC Reliability Standards – Endorsed by email vote on February 11, 2020
   c. White Paper: Inverter-Based Resource Monitoring – Approved (projected) by email vote

3. Subcommittee Leadership Reports and PC Work Plan Updates*
   a. Performance Analysis Subcommittee (PAS) – Maggie Peacock
      i. Generator Availability Data System Working Group (GADSWG)
      ii. Transmission Availability Data System Working Group (TADSWG)
      iii. Misoperations Information Data and Analysis System Working Group (MIDASWG)
   b. Reliability Assessment Subcommittee (RAS) – Lewis De La Rosa
      i. Probabilistic Assessment Working Group (PAWG)
   c. System Protection & Control Subcommittee (SPCS) – Jeff Iler
   d. Synchronized Measurements Subcommittee (SMS) – Tim Fritch
   e. System Analysis and Modeling Subcommittee (SAMS) – Evan Shuvo
      i. Load Modeling Task Force (LMTF)
ii. Power Plant Modeling and Verification Task Force (PPMVTF)

f. Inverter-based Resource Performance Task Force (IRPTF) – Jeff Billo

g. System Planning Impacts from Distributed Energy Resource Working Group (SPIDERWG) – Ryan Quint / JP Skeath

h. Geomagnetic Disturbance Task Force (GMDTF) – Ian Grant

4. Committee Discussion Items*


5. Reliability Guidelines*


6. Items for Approval, Endorsement, Acceptance, or Authorization*


   i. Proposed Standards Authorization Request (SAR) – Endorse

d. NERC Rules of Procedure Section 1600 Data Request for Generator Availability Data System (GADS Data Request) – Authorize Posting for Comment – Donna Pratt

7. Discussion Topics– Information*


8. Member Roundtable

9. Closing Remarks – Brian Evans-Mongeon

10. Adjournment

11. Future In-person Meetings

a. March 31 – April 1 | PCEC Strategic Meeting | Austin

b. June 10-11 | RSTC Meeting | Location TBD | For RSTC members and observers

*Background materials included, if appropriate.
White Paper: TPL-001 Assessment and DER Impacts

Action
Discussion

Background
In December 2019, SPIDERWG presented the attached white paper to the PC and requested PC reviewers. Comments were submitted by reviewers on or before February 7, 2020. PC leadership requested SPIDERWG discuss comments with the PC and lead a discussion on the scope and recommendations in the white paper.

Many areas of the North American bulk power system (BPS) are experiencing a transition towards increasing penetrations of distributed energy resources (DERs). NERC Reliability Standard TPL-001-4 was developed under a paradigm of predominantly BPS-connected generation, when penetrations of DERs were significantly lower than current and future projections. The scope of recent modifications to TPL-001-5 did not include considering the impacts of DER on BPS planning. Therefore, the NERC System Planning Impacts of DER Working Group (SPIDERWG) undertook the task of evaluating the sufficiency and clarity of the TPL-001 standard for considering DER as part of annual Planning Assessment. The definition of DER is to be consistent with DER as included in MOD-032-1 Standard Authorization Request (SAR). This white paper discusses the impacts of DER on the standard requirements in three distinct ways:

1. Is the requirement relevant for consideration of DER?
2. Does the existing requirement language preclude consideration of DER in any way?
3. Is the requirement language clear regarding consideration of DER?

Insights from the discussion with the PC will help determine next steps.
White Paper
Assessment of DER impacts on NERC Reliability Standard TPL-001
NERC System Planning Impacts of Distributed Energy Resources
(SPIFERWG)
December 2019

Executive Summary
Many areas of the North American bulk power system (BPS) are experiencing a transition towards increasing penetrations of distributed energy resources (DERs). NERC Reliability Standard TPL-001-4 was developed under a paradigm of predominantly BPS-connected generation, when penetrations of DERs were significantly lower than current and future projections. The scope of recent modifications to TPL-001-5 did not include considering the impacts of DER on BPS planning. Therefore, the NERC System Planning Impacts of DER Working Group (SPIFERWG) undertook the task of evaluating the sufficiency and clarity of the TPL-001 standard for considering DER as part of annual Planning Assessment. The definition of DER is to be consistent with DER as included in MOD-032-1 Standard Authorization Request (SAR). This white paper discusses the impacts of DER on the standard requirements in three distinct ways:

1. Is the requirement relevant for consideration of DER?
2. Does the existing requirement language preclude consideration of DER in any way?
3. Is the requirement language clear regarding consideration of DER?

Table 1 shows the key findings and recommendations from the SPIFERWG review of TPL-001 regarding impacts of DER on the standard requirements and industry implementation of the standard. This white paper does not provide solutions to the gaps identified; rather, the intent is to highlight potential gaps or areas for improvement within TPL-001 such that a SAR can be developed, as needed, to address various issues by a Standard Drafting Team (SDT).

Based on the detailed SPIFERWG review of TPL-001, SPIFERWG recommends a SAR be developed that includes each of the following issues and that a future SDT assess the extent to which changes or implementation guidance are needed for each of these issues:

- Clarify Requirements R2.1 and R2.2 regarding use of phrase “System peak Load”. This should be updated to consider “System net or gross peak demand”, and sensitivity studies should consider “System net or gross peak demand” if the two conditions are significantly different from one another in either magnitude or locational spread.\(^1\) The SDT should consider whether terms should be added to the NERC Glossary of Terms for “Gross Demand” and “Net Demand” so there is no misinterpretation of what these terms refer to.

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\(^1\) As the penetration of DER increases, the peak demand seen at the transmission-distribution interface can become significantly different at different locations.
- Clarify Requirement R2.4 regarding capturing the dynamic behavior of DER, similar to the existing language used for induction motor loads in Requirement R2.4.1. Representation of the dynamic behavior of aggregate DERs should be applicable to all stability simulations, not just System peak conditions.

- Clarify Requirement R3.1 and R3.4 in regards to whether and how DER should be considered as a potential contingency.

- Clarify Requirement R3.3 in regards to the extent to which DER are considered in contingency definitions. While requirement R1.1.5 uses the term “resource” (which includes demand side resources2), Requirement R3.3 uses the term “generator” which is not a defined term in the NERC Glossary and typically does not include DERs. Therefore, it is unclear whether aggregate amounts of DER tripping should be considered in this assessment.

- Clarify Requirements R4.1.1 and R4.1.2 regarding representing the dynamic behavior of aggregate DERs and the performance requirements applicable to aggregate DERs during stability simulations. For example, the language referring to “pulls out of synchronism” is only relevant to synchronous generation and is not applicable to inverter-based generation (including inverter-based DER). Large amounts of aggregate DER tripping on low/high voltage/frequency conditions can adversely affect BPS performance and may pose a risk to system stability, uncontrolled separation, or cascading events if not properly studied and identified ahead of real-time operations. The language should be clarified to address these issues.

- Clarify Requirement R4.3.1.2 in regards to the “generators” referenced in the language are inclusive of aggregate representation of DERs since tripping of large amounts of DER can have an adverse impact on BPS stability performance. This may require the use of a different term in this requirement since “generators” may not apply broadly to all uses in the standard. Hence, a definition of “generators” in the NERC Glossary, and correct distinction of where these generators are located,3 is preferred.

- Clarify Requirement R4.3.2 regarding representation of the dynamic behavior of aggregate DER (e.g., aggregate DER tripping, dynamic voltage and frequency controls, momentary cessation, etc.) should be considered in stability analyses.

<table>
<thead>
<tr>
<th>Requirement</th>
<th>Key Findings and Recommendations</th>
</tr>
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</table>
| R1          | • This requirement is relevant for consideration of DER.  
             • The existing language does not preclude consideration of DER.  
             • The existing language is clear for consideration of DER. |

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2 Which means that DER is included in this term “resources”.

3 For example, BPS-connected generators, BES generators, or all generators including aggregate DER generators.
### Table 1: Key Findings from SPI DERWG Review

<table>
<thead>
<tr>
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<th>Key Findings and Recommendations</th>
</tr>
</thead>
</table>
| R2.1        | • This requirement **is** relevant for consideration of DER.  
              • The existing language **does not** preclude consideration of DER.  
              • The existing language **is not** clear for consideration of DER. |
| R2.2        | • This requirement **is** relevant for consideration of DER.  
              • The existing language **does not** preclude consideration of DER.  
              • The existing language **is not** clear for consideration of DER. |
| R2.3        | • This requirement **is** relevant for consideration of DER.  
              • The existing language **does not** preclude consideration of DER.  
              • The existing language **is** clear for consideration of DER. |
| R2.4        | • This requirement **is** relevant for consideration of DER.  
              • The existing language **does not** preclude consideration of DER.  
              • The existing language **is not** clear for consideration of DER. |
| R2.5        | • This requirement **is** relevant for consideration of DER.  
              • The existing language **does not** preclude consideration of DER.  
              • The existing language **is** clear for consideration of DER. |
| R2.6        | • This requirement **is** relevant for consideration of DER.  
              • The existing language **does not** preclude consideration of DER.  
              • The existing language **is** clear for consideration of DER. |
| R2.7        | • This requirement **is** relevant for consideration of DER.  
              • The existing language **does not** preclude consideration of DER.  
              • The existing language **is** clear for consideration of DER. |
| R2.8        | • This requirement **is** relevant for consideration of DER.  
              • The existing language **does not** preclude consideration of DER.  
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| R3.1        | • This requirement **is** relevant for consideration of DER.  
              • The existing language **does not** preclude consideration of DER.  
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| R3.2        | • This requirement **is** relevant for consideration of DER.  
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## Table 1: Key Findings from SPI DERWG Review

<table>
<thead>
<tr>
<th>Requirement</th>
<th>Key Findings and Recommendations</th>
</tr>
</thead>
</table>
| R3.4        | • This requirement is relevant for consideration of DER.  
              • The existing language does not preclude consideration of DER.  
              • The existing language is not clear for consideration of DER. |
| R3.5        | • This requirement is relevant for consideration of DER.  
              • The existing language does not preclude consideration of DER.  
              • The existing language is clear for consideration of DER. |
| R4.1        | • This requirement is relevant for consideration of DER.  
              • The existing language does not preclude consideration of DER.  
              • The existing language is not clear for consideration of DER. |
| R4.2        | • This requirement is relevant for consideration of DER.  
              • The existing language does not preclude consideration of DER.  
              • The existing language is clear for consideration of DER. |
| R4.3        | • This requirement is relevant for consideration of DER.  
              • The existing language does not preclude consideration of DER.  
              • The existing language is not clear for consideration of DER. |
| R4.4        | • This requirement is relevant for consideration of DER.  
              • The existing language does not preclude consideration of DER.  
              • The existing language is clear for consideration of DER. |
| R4.5        | • This requirement is relevant for consideration of DER.  
              • The existing language does not preclude consideration of DER.  
              • The existing language is clear for consideration of DER. |
| R5          | • This requirement is not relevant for consideration of DER. |
| R6          | • This requirement is not relevant for consideration of DER. |
| R7          | • This requirement is not relevant for consideration of DER. |
| R8          | • This requirement is not relevant for consideration of DER. |
Chapter 1 - Requirement R1
Standard Requirement R1

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1.

- **R1.1.** System models shall represent:
  - R1.1.1. Existing Facilities
  - R1.1.2. New planned Facilities and changes to existing Facilities
  - R1.1.3. Real and reactive Load forecasts
  - R1.1.4. Known commitments for Firm Transmission Service and Interchange
  - R1.1.5. Resources (supply or demand side) required for Load

**SPIIDERWG Review Finding**

- This requirement is relevant for consideration of DER.
- The existing language does not preclude consideration of DER.
- The existing language is clear for consideration of DER.

**Supplemental Discussion**

As higher levels of DER are integrated across the Bulk Power System, aggregated DER should be part of system modeling. Aggregated DER is included in R1.1.5 (“Resources (supply or demand side)”). Aggregated DER data collection is also proposed in the MOD-032-1 SAR to further reinforce the current understanding and need for inclusion of DER in BPS models used for planning assessments. While no specific threshold for aggregated DER modeling is suggested, each entity should keep track of aggregated DER to make such determinations. If the interconnecting utility is required to be notified of any newly connected DER, the data should exist for all installations of required size. If the data is available, then aggregated DER should be accounted for in the system model. Several other NERC Reliability Guidelines detail how the aggregated DER should be modeled.\(^4\)\(^5\)\(^6\) For R-DER, it is sufficient to model the aggregated DER as a component of the composite load model, which reduces the level of effort and complexity required to incorporate while still providing valuable modeling enhancements.

It is noted that the MOD-032 SAR being proposed by SPIIDERWG is seeking to include aggregate DER information as a necessary modeling component for BPS planning assessments. The SAR seeks aggregate

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DER information on steady-state and dynamics data, and does not seek changes to the short circuit requirement “as steady-state column should have necessary information related to positive, negative, and zero sequence data provided accordingly”.

Chapter 2 – Requirement R2

Standard Requirement R2

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses.

Standard Requirement R2.1

R2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:

- **R2.1.1.** System peak Load for either Year One or year two, and for year five.
- **R2.1.2.** System Off-Peak Load for one of the five years.
- **R2.1.3.** For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response:
  - Real and reactive forecasted Load.
  - Expected transfers.
  - Expected in service dates of new or modified Transmission Facilities.
  - Reactive resource capability.
  - Generation additions, retirements, or other dispatch scenarios.
  - Controllable Loads and Demand Side Management.
  - Duration or timing of known Transmission outages.

SPIDERWG Review Finding

- This requirement is relevant for consideration of DER.
- The existing language does not preclude consideration of DER.
- The existing language is not clear for consideration of DER.
**Supplemental Discussion**

Load is defined in NERC Glossary of Terms as “An end-use device or customer that receives power from the electric system.” When referring to “gross load” (or “gross demand”), this refers to the total amount of power consumed by these end-use loads. With increased penetration of DER, the net load (net load = gross load – DER output) as seen at the T-D interface can be higher during operating conditions that are not at the gross peak demand hour. Simply referring to “System peak Load” in the TPL-001 standard does not make it clear as to whether gross load or net load should be used, or whether there is flexibility for the TP and PC to determine which is more appropriate for their system. One could argue that the highest gross loading was assumed when DER penetration was minimal; however, today DER penetration is causing the maximum net load at the gross peak condition to be lower than the net load at the net peak condition. As such, the term “System peak Load” generates different interpretations and confusion regarding what snapshot the scenario should represent. This raises the risk that entities may be interpreting this to mean either, which could lead to increasingly disparate planning assumptions in the future. This issue should be addressed in a revision to the TPL-001 standard to clarify the intent and how TPs and PCs should implement the standard.

In addition to magnitude differences between gross and net load, the dispersion or spread of net load can vary significantly from gross load if DER is not spread evenly in proportion to local load levels. As a result, even similar total gross and net system load levels can have different impacts on the BPS if DER is spread unevenly relative to load.

Consistent with the NERC Reliability Guideline for DER modeling, DER should be modeled explicitly (no load netting). DER capacity and output in peak and off-peak load conditions should be modeled consistent with the year and the snapshot hour that the scenario represents. Sensitivity scenarios could include different output levels for DER (e.g., due to cloud cover or due to different operating hour assumptions). “Other dispatch scenarios” cover different DER output levels appropriately.

The SDT should consider whether the terms “Gross Demand” and “Net Demand” should be added to the NERC Glossary of Terms so that there is no misinterpretation of what these terms refer to. When selecting powerflow base case conditions to study for Planning Assessment, this distinction is quite important.

**Standard Requirement R2.2**

- **R2.2.** For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:
  - **R2.2.1.** A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected

**SPIDERWG Review Finding**

- This requirement is relevant for consideration of DER.
• The existing language does not preclude consideration of DER.
• The existing language is not clear for consideration of DER.

**Supplemental Discussion**
Same comments as R2.1 on “definition of “System peak”.

**Standard Requirement R2.3**

R2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

**SPIDERWG Review Finding**

• This requirement is relevant for consideration of DER.
• The existing language does not preclude consideration of DER.
• The existing language is clear for consideration of DER.

**Supplemental Discussion**
Make sure that inverter-based DERs are modeled appropriately in the short circuit model using the latest developed models that reflect the converter interface. Unlike synchronous generators, the short circuit current contribution from the inverter-based generation is usually limited to 100-120% of the rated load current\(^7\). If a voltage-controlled current source (VCCS) model is used, the angular relationship between inverter terminal voltage and current injected by the inverter is needed\(^8\). These power factor angles are important to achieve accurate results from the study.

**Standard Requirement R2.4**

• **R2.4.** For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:
  
  ▪ **R2.4.1** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

  ▪ **R2.4.2.** System Off-Peak Load for one of the five years.

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\(^7\) See the *IEEE Joint Working Group Report, Fault Current Contributions from Wind Plants, 2013* for more details ([http://www.pes-psrc.org/kb/published/reports/Fault%20Current%20Contributions%20from%20Wind%20Plants.pdf](http://www.pes-psrc.org/kb/published/reports/Fault%20Current%20Contributions%20from%20Wind%20Plants.pdf)).

\(^8\) TECHNICAL BULLETIN ON MODELING TYPE-4 WIND PLANT AND SOLAR PLANTS: [https://www.aspeninc.com/web/support/user-downloads](https://www.aspeninc.com/web/support/user-downloads).
• **R2.4.3.** For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:
  - Load level, Load forecast, or dynamic Load model assumptions.
  - Expected transfers.
  - Expected in service dates of new or modified Transmission Facilities.
  - Reactive resource capability.
  - Generation additions, retirements, or other dispatch scenarios.

• **R2.4.4.** When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum, those known outages expected to produce more severe System impacts on the Planning Coordinator or Transmission Planner’s portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.

• **R2.4.5.** When an entity’s spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed. Based upon this assessment, an analysis shall be performed for the selected P1 and P2 category events identified in Table 1 for which the unavailability is expected to produce more severe System impacts on its portion of the BES. The analysis shall simulate the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

**SPIDERWG Review Finding**

- This requirement is relevant for consideration of DER.
- The existing language does not preclude consideration of DER.
- The existing language is not clear for consideration of DER.

**Supplemental Discussion**
Similar comment as in R2.1 and 2.2 in regards to the terms “System peak Load” and “System Off-Peak Load”. Consistent with the NERC Reliability Guideline for DER modeling, aggregate DERs should be modeled explicitly (no load netting). Aggregate DER capacity and output in peak and off-peak load conditions should
be modeled consistent with the year and the snapshot hour that the case represents. For the expected
dynamic behavior of aggregate System Load, aggregate DERs should be represented appropriately as either
a generator model or a DER component of the load record in stability analysis. Consistent with the NERC
Reliability Guideline for modeling DER in Dynamic Load Models, inverter-based DER can be represented in
Stability analysis using the DER_A model. The NERC Reliability Guideline for parameterization of the DER_A
model can be used for developing required parameters. In addition, language regarding capturing the
dynamic behavior of DER should be added for clarity, similar to the language used for representing induction
motor loads in the current TPL-001 version. However, representation of the dynamic behavior of aggregate
DERs is critical in all stability studies, not just System peak conditions.

Standard Requirement R2.5

- **R2.5.** For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the
Stability analysis shall be assessed to address the impact of proposed material generation
additions or changes in that timeframe and be supported by current or past studies as qualified in
Requirement R2, Part2.6 and shall include documentation to support the technical rationale for
determining material changes.

**SPIDERWG Review Finding**

- This requirement is relevant for consideration of DER.
- The existing language does not preclude consideration of DER.
- The existing language is clear for consideration of DER.

**Supplemental Discussion**

Same comments as R2.3.

Standard Requirement R2.6

- **R2.6.** Past studies may be used to support the Planning Assessment if they meet the following
requirements:
  - **R2.6.1.** For steady state, short circuit, or Stability analysis: the study shall be five calendar years
    old or less, unless a technical rationale can be provided to demonstrate that the results of an
    older study are still valid.
  - **R2.6.2.** For steady state, short circuit, or Stability analysis: no material changes have occurred
    to the System represented in the study. Documentation to support the technical rationale for
determining material changes shall be included.

**SPIDERWG Review Finding**

- This requirement is relevant for consideration of DER.
- The existing language does not preclude consideration of DER.
- The existing language is clear for consideration of DER.
Supplemental Discussion
Consider change in DER penetration level in determining material change for evaluation of use of past studies. As DER penetration increases along with the gross load, the net load growth at the T-D interface could remain flat or even decline. This may result in similar steady-state result as in past studies, depending on how evenly the DER is spread relative to the load. However, could result in very different dynamic performance due to the change in load composition and dynamic behavior of the DER. It is not clear whether a change in inverter technology request by Resource Entity qualifies as material change.

Standard Requirement R2.7

- **R2.7.** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: [Requirements 2.7.1 – 2.7.4]

  - **R2.7.1.** List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:
    - Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
    - Installation, modification, or removal of Protection Systems or Remedial Action Schemes.
    - Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
    - Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
    - Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
    - Use of rate applications, DSM, new technologies, or other initiatives.

  - **R2.7.2.** Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

  - **R2.7.3.** If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission
Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

- **R2.7.4.** Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

**SPIDERWG Review Finding**

- This requirement is relevant for consideration of DER.
- The existing language does not preclude consideration of DER.
- The existing language is clear for consideration of DER.

**Supplemental Discussion**

DER could alleviate system deficiencies by reducing net load and reducing flows on the bulk power system, depending on how DER is spread relative to the load. As such, DER could be part of CAP and could be included within the list of actions needed to achieve required system performance. It can be interpreted that the current language in the standard “Use of rate applications, DSM, new technologies or other initiatives” includes DER. If not included in above, DER should be explicitly included in the list.

**Standard Requirement R2.8**

- **R2.8.** For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:
  - **R2.8.1.** List System deficiencies and the associated actions needed to achieve required System performance.
  - **R2.8.2.** Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

**SPIDERWG Review Finding**

- This requirement is relevant for consideration of DER.
- The existing language does not preclude consideration of DER.
- The existing language is clear for consideration of DER.

**Supplemental Discussion**

DERs fault contribution characteristics could be considered as part of remedial actions assessment. Similar to 2.7 above, DER could be part of CAP and could be included within the list of actions needed to address the equipment rating violations. “Use of rate applications, DSM, new technologies or other initiatives”.

**Chapter 3 - Requirement R3**
Standard Requirement R3

- **R3.** For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1.

Standard Requirement 3.1

- **R3.1.** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

SPI DERWG Review Finding

- This requirement is relevant for consideration of DER.
- The existing language does not preclude consideration of DER.
- The existing language is not clear for consideration of DER.

Supplemental Discussion

Contingency analysis should consider the aggregate impact of DERs on the BPS. The current language might not be clear regarding whether and how to consider DERs. For example, should the loss of a generator include the loss of aggregated DER if the aggregated loss is sufficiently large enough (even if it only has a local impact on BPS performance)? While it is more accurate to include both U-DER and R-DER, it may be challenging to include R-DER if they are modeled as embedded in the load record.

Standard Requirement R3.2

- **R3.2.** Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

SPI DERWG Review Finding.

- This requirement is relevant for consideration of DER.
- The existing language does not preclude consideration of DER.
- The existing language is clear for consideration of DER.

Supplemental Discussion

With heavy penetration of DER, extreme events could include impacts of DER. Events like wide-area cloud cover and solar eclipse could significantly reduce DER output (predominantly solar) in a relatively short time (in addition to the reduction of BPS-connected solar PV generation). Based on discussions within SPI DERWG, this should not be considered a contingency due to its time frame. Rather, TPs and PCs should consider
developing base case scenarios that account for the spatial aspects and any common modes that could affect DER output.

Large amounts of aggregate DER could trip following other contingencies (e.g., loss of transmission circuits), and this can amplify the impact of the triggering contingency (as was observed in the UK disturbance in summer 2019). Existing language in Table 1 on extreme events is sufficient to allow such DER considerations by 3.b “Other events based upon operating experience that may result in wide area disturbances.”

**Standard Requirement R3.3**

- **R3.3.** Contingency analyses for Requirement R3, Parts 3.1 and 3.2 shall:
  - **R3.3.1.** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:
    - R3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.
    - R3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.
  - R3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

**SPIDERWG Review Finding**

- This requirement is relevant for consideration of DER.
- The existing language does not preclude consideration of DER.
- The existing language is not clear for consideration of DER.

**Supplemental Discussion**

DERs should be tripped where simulations show load bus voltages that are less than known or assumed minimum DER steady-state or ride-through voltage limits. It is also recommended to include in the assessment any assumptions made in estimating DER bus voltage. The existing language does not preclude consideration of DER. R1 specifies that the “System models” for the “Planning Assessment” discussed in R3 must: “Use data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed” and “System models shall represent: ...1.1.5 Resources (supply or demand side) required for Load.” Thus, R3 does not preclude the consideration of DER by the PC and TP. After all, (1) under MOD-032-1, the PC and TP may already request DER data “necessary for modeling purposes” and (2) DER is a “demand side” resource increasingly required for serving load. However, although the term “generators” may include DER, it is not clear that it does. R1.1.5 uses the term “Resources” when specifying inclusion of demand side resources, but R3.3 used the term “generators” which is not a defined term in the
NERC Glossary. Therefore, it is not clear whether it includes DERs. Terminology and consideration for DER should be addressed by language modifications to bring clarity to the requirements.

**Standard Requirement R3.4**

- **R3.4.** Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.
  - **R3.4.1.** The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

**Review Finding**

- This requirement is relevant for consideration of DER.
- The existing language does not preclude consideration of DER.
- The existing language is not clear for consideration of DER.

**Supplemental Discussion**

Same comments as R3.1.

**Standard Requirement R3.5**

- **R3.5.** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

**SPIIDERWG Review Finding**

- This requirement is relevant for consideration of DER.
- The existing language does not preclude consideration of DER.
- The existing language is clear for consideration of DER.

**Supplemental Discussion**

Same comments as R3.2

**Chapter 4 – Requirement R4**

**Standard Requirement R4**

- **R4.** For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency
analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1.

**Standard Requirement R4.1**

- **R4.1.** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.
  - **R4.1.1.** For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.
  - **R4.1.2.** For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.
  - **R4.1.3.** For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planning Engineer.

**SPIDERWG Review Finding**

- This requirement is relevant for consideration of DER.
- The existing language does not preclude consideration of DER.
- The existing language is not clear for consideration of DER.

**Supplemental Discussion**

In Requirements R4.1.1 and R4.1.2, performance criteria “pulls out of synchronism” is specific to synchronous generators and is not addressing performance requirement for asynchronous generators including DER. The language should be clarified to address performance requirements for both types of resources.

**Standard Requirement R4.2**

- **R4.2.** Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event (s) shall be conducted.

**SPIDERWG Review Finding**

- This requirement is relevant for consideration of DER.
- The existing language does not preclude consideration of DER.
- The existing language is clear for consideration of DER.
Supplemental Discussion
Same comments as 3.2 Dynamic contingencies should include DER tripping for voltage/frequency.

Standard Requirement R4.3

- **R4.3.** Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall:
  - **R4.3.1.** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:
    - **R4.3.1.1.** Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.
    - **R4.3.1.2.** Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
    - **R4.3.1.3.** Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.
  - **R4.3.2.** Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

SPIDERWG Review Finding

- This requirement is relevant for consideration of DER.
- The existing language does not preclude consideration of DER.
- The existing language is not clear for consideration of DER.

Supplemental Discussion
DERs should be tripped where simulations show load bus voltages that are less than known or assumed minimum DER ride-through voltage limits. It is also recommended to include in the assessment any assumptions made in estimating DER bus voltage. The existing language does not preclude consideration of DER. R1 specifies that the “System models” for the “Planning Assessment” discussed in R4 must: “Use data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed” and “System models shall represent: ...1.1.5 Resources (supply or demand side) required for Load.” Thus, R4 does not preclude the consideration of DER by the PC and TP. After all, (1) under MOD-032-1, the PC and TP may already request DER data “necessary for modeling purposes” and (2) DER is a “demand side” resource increasingly required for serving load. However, although the term “generators” may include DER, it is not clear that it does. R1.1.5 uses the term “Resources” when specifying inclusion of demand side resources, but R4.3 used the term “generators” which is not a defined term in the NERC Glossary. Therefore, it is not clear whether it includes DERs. Terminology and consideration for DER should be addressed by
language modifications to bring clarity to the requirements. Requirement R4.3.2 should include DER’s dynamic controls such as DER tripping, dynamic reactive support, active power-frequency control, etc.

Standard Requirement R4.4

- **R4.4.** Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.
  - **R4.4.1.** Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

SpiderWG Review Finding

- This requirement is relevant for consideration of DER.
- The existing language does not preclude consideration of DER.
- The existing language is clear for consideration of DER.

Supplemental Discussion

Same comments as R3.1.

Standard Requirement R4.5

- **R4.5.** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

SpiderWG Review Finding

- This requirement is relevant for consideration of DER.
- The existing language does not preclude consideration of DER.
- The existing language is clear for consideration of DER.

**Supplemental Discussion**

Same comments as R4.2.

**Chapter 5 - Requirements R5-R8**

**Standard Requirement R5**

- **R5.** Each Transmission Planning Engineer and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the
transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level.

**Standard Requirement R6**

- R6. Each Transmission Planning Engineer and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding.

**Standard Requirement R7**

- R7. Each Planning Coordinator, in conjunction with each of its Transmission Planning Engineers, shall determine and identify each entity’s individual and joint responsibilities for performing the required studies for the Planning Assessment.

**Standard Requirement R8**

- R8. Each Planning Coordinator and Transmission Planning Engineer shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planning Engineers within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request.

- R8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planning Engineer shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

**SPI DERWG Review Finding**

- Requirements R5–R8 are not relevant for consideration of DER.

**Action**
Discussion

**Background**
At the January PCEC web meeting, members of the PCEC volunteered to review the attached white paper developed by PPMVTF. Comments were submitted by reviewers on or before February 18, 2020. PC leadership requested SAMS and NERC Staff discuss comments with the PC and lead a discussion on the scope and recommendations in the white paper.

PPMVTF developed the attached white paper address the activities related to testing, coordination, and modeling of generator capability in MOD-025-2. The Purpose section of MOD-025-2 states that verification and data reporting activities of GOs regarding generator (and synchronous condenser) active and reactive power capability testing are performed “to ensure that accurate information on generator gross and net Real and Reactive Power capability and synchronous condenser Reactive Power capability is available for planning models used to assess Bulk Electric System (BES) reliability.” In the white paper, PPMVTF examines the potential for the tests and provisions in the standard to fail to demonstrate the generator reactive power capability, resulting in the potential for inaccurate data to be used in planning models.

Insights from the discussion with the PC will help determine next steps.

**Summary**

*Leave Blank for meeting participant notes*
NERC Power Plant Modeling and Verification Task Force (PPMVTF)
July 2019

Summary
The purpose of MOD-025-2 states that verification and data reporting activities of GOs regarding generator (and synchronous condenser) active and reactive power capability testing are performed “to ensure that accurate information on generator gross and net Real and Reactive Power capability and synchronous condenser Reactive Power capability is available for planning models used to assess Bulk Electric System (BES) reliability.” However, unless the actual generator capability limits (including limiters) are reached during testing, the test data should not be directly used for transmission planning modeling purposes. Reaching the reactive power capability limits, particularly the excitation system over-excitation (OEL) and under-excitation (UEL) limiters, during operation is a rare event. Therefore, historical operational data might help the verification of the active power capability of the unit, but might not contain a single event (ever) where the equipment reached its limits regarding reactive power capability. While MOD-025-2 includes the option for using historical operational data, this operational data is typically insufficient for verifying reactive power capability (i.e., likely only capturing one of the four data points required to verify per MOD-025-2). Therefore, this white paper is focused on the staged testing aspects of MOD-025-2.

In some cases, the generator reactive power capability is not fully demonstrated during testing; rather, other constraints such as generator terminal voltage, plant auxiliary bus voltage, or system operating voltage limits prevent reaching the generator reactive power capability. In these cases, if values reached during testing are reported per MOD-025-2 requirements, the generating unit capability will be underestimated (perhaps severely). Therefore, pre-test considerations and/or post-test engineering analyses are necessary in these cases. In cases where the reactive power limits, such as enforced by overexcitation limiters (OELs) and underexcitation limiters (UELs) are indeed reached under test conditions, the measured reactive power will be less than that described by the generator capability curves (“D curves”). While it is suggested in Attachment 1 of MOD-025 that engineering analysis be used to adjust the data to account for the effects for voltage, it is not required.

In many cases, the demonstrated test data if reported as required by MOD-025-2 will not accurately represent the actual generating unit capability. Using this information to represent generator capability in planning studies will result in inaccurate models. The stated purpose of MOD-025-2 will then be thwarted, and therefore the standard fails to meet its intended purpose.

It is therefore recommended that a Standard Authorization Request (SAR) be developed, and a Standard Drafting Team (SDT) be created, to address the issues described in this white paper related to MOD-025-2.

1 For this reason, most generating facilities will use staged testing for the purposes of meeting the requirements of MOD-025-2.
2 Typically the auxiliary buses are not represented in the transmission planning models. Further, bus voltage limits are modeled or monitored separately from generator capability.
The PPMVTF is of the opinion that the existing MOD-025-2 standard should be either (i) altered or (ii) withdrawn and replaced with a new standard entirely.³ The changes needed to MOD-025-2 are to prevent inaccurate data from being used to represent generating resources (and synchronous condensers) in the planning models. The PPMVTF believes that there is value in performing the tests since they can uncover unexpected limiting factors; however, the PPMVTF agrees that the data acquired during MOD-025-2 testing may not be directly usable to represent the actual capability of the machine in power system models, and that the tests do not generally accomplish the stated purpose of the standard.

**Background**

The curves on a generator capability diagram are depictions of the thermal limits of the rotor, stator, and stator end iron at generator rated voltage (and various pressures, if the case) at given generator active and reactive loading conditions. These curves, in combination with appropriate field current and voltage limits (i.e., underexcitation limiter (UEL) and overexcitation limiter (OEL)) supplied as part of MOD-032-1, represent the active and reactive power capabilities at rated generator terminal voltage.⁴ To manipulate reactive power output of a generator for MOD-025-2 data collection, either the local transmission system voltage or the generator terminal voltage must be varied. As it may often be infeasible to sufficiently alter local transmission system voltage for such a test,⁵ the test is generally conducted by varying the generator terminal voltage. Based on the short circuit strength of the system at the generator interconnection, this could result in a significant increase or decrease in generator terminal voltage during testing. As illustrated in Figure 1, generator capability is strongly dependent on generator terminal voltage.

If MOD-025-2 data is collected by raising and lowering generator terminal voltage (from a starting point near the rated value) to reach the reactive capability limit of a generator (e.g., as determined by an OEL and UEL), the reactive power limit will change with terminal voltage. The net reactive power production and absorption can be significantly less

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³ A minority opinion is that MOD-025-2 should be withdrawn and not replaced with another standard.

⁴ Sometimes these curves can be provided by the manufacturer at different terminal voltage values.

⁵ Note that the transmission system voltage limits are usually defined by a voltage schedule provided by the Transmission Operator, and must be adhered to by the GO per their established policies and NERC Reliability Standards.
than the generator would provide under rated voltage conditions. As shown in Figure 2, the targeted reactive power capability operating test points are shifted with the changing voltage, and less reactive power is achieved.

![Testing Generator Capability](image)

**Figure 2: Reactive Capability – Test versus Target Limits**

If the actual limiting factors displayed on the capability curves (e.g., OEL and UEL) cannot be reached during the tests, then engineering analysis can be done to calculate the power output that would result if the terminal voltage was at the rated value. Figure 3 shows an example of this.
In this case, the voltages were adjusted until the OEL and UEL were reached. The tested values of voltage, active power, reactive power, and field current were used to recalculate the generator output if voltages were adjusted to the rated value. The capability curves are then verified by test and accurate for studies. Since testing is most often conducted by changing the terminal voltage, it is possible to reach a reactive power output where restrictions will apply before the actual generator capability limit is reached. In this case, the demonstrated test values will underestimate the reactive capability of the generator. A detailed discussion can be found in the NERC Reliability Guideline: Power Plant Model Verification and Testing for Synchronous Machines.  

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The reactive capability of a generator is used to maintain transmission system voltages within the acceptable operating range, by supplying reactive power to the system when voltage is too low, and absorbing reactive power when voltage is too high. Currently, commercial load flow software does not account for the relationship between voltage and generator reactive power limits. The software considers a fixed value for reactive power capability that is not dependent on generator terminal voltage. The most common practice is to use capability values for rated terminal voltage (from the composite D curve) as shown by the blue curve in Figure 2. Using the tested values in MOD-025-2 at off-nominal voltage may underestimate the capability of the machine (severely, in some cases). This is illustrated by the red curve in Figure 2 for the over-excited region. This leads to pessimistic⁷ data used in transmission planning studies.

Pre-test adjustments may be required to collect a more accurate raw data that better reflect the steady-state generator capabilities. An example of pre-test adjustments is to utilize other generating units within the same plant or in close electric proximity to withdraw reactive power from the transmission system during reactive power injection testing of the generating unit under test, and vice versa. Another example is to coordinate the time of test with the Transmission Operator to allow for some transmission system adjustments (possibly an abnormal system voltage level or reactive devices such as capacitor banks in the local area switched on to absorb some of the reactive power produced by the unit under test). While these types of system adjustments may facilitate MOD-025-2 testing of a unit, they could also represent a reliability concern (i.e., voltage excursion) if the generating unit under test were to trip.⁸ If pre-test adjustments are not achievable, engineering analyses can be performed to modify the collected raw test data to reflect more accurate generation capabilities or use in planning models. An example of engineering analyses is to scale the rated rotor current curve or OEL curve to reflect rated voltage. Although engineering calculations can be used in some cases to reflect the test data to rated voltage capability limits, this is not a mandatory task (nor always usable) per MOD-025-2.

Therefore, the only generator capability information that should be submitted for planning models to assess Bulk Electric System reliability is that defined on the generator rated terminal voltage and as reported in accordance with MOD-032-1. However, MOD-032-1 does not require validation or measurements to verify the accuracy of the capability curves.

Note 1 and Note 2 of Attachment 1 of MOD-025-2 acknowledge that the data collected in accordance with the standard will often not conform to the rated voltage generator capability diagram, and will thereby not result in the verification of the actual generator reactive power capability. Since the stated purpose of MOD-025-2 is to ensure the accuracy of generator capability information for planning models, there is a conflict between MOD-025-1 and MOD-032-1 if it is interpreted that data collected in accordance with MOD-025-2 should be used to set limits in the planning models. This should not be the case, and has led to industry confusion, and potentially inaccurate modeling. MOD-032-1 is the standard for reporting this data and should use the actual expected composite capability curve limits (generator capability curve and associated OEL and UEL) in the models.

⁷ Pessimistic or overly restrictive generator reactive capability modeled in planning cases could lead to BPS reactive power deficiencies, which could lead to unnecessary system upgrades.

⁸ Therefore, based on experience performing MOD-025-2 testing, generally the Transmission Operator will not be amenable to significant modifications to scheduled voltages for the purposes of MOD-025-2 testing (to ensure reliable operation).
Some of the benefits of performing the testing in MOD-025-2 include, but are not limited to, those listed below. These are provided here as reference to the operational benefits, although it is noted that these do not support the development of planning models (the stated purpose of MOD-025-2).

1. Identification of previously unknown trips or limiting conditions, such as: motor control center undervoltage relay trips, underrated GSUs, overlooked auxiliary motor voltages, operation of cooling systems below rating (e.g., hydrogen pressure set to levels below rated capability curves), etc. Once understood, plants can take action to eliminate or mitigate potential issues from these by correction of settings, provisions of alarms, training, operational procedures, etc.

2. While NERC PRC-019-1 (and to an extent PRC -024-2) requirements have improved coordination of relays to prevent unexpected trips, there is no replacement for actual testing of units to reasonable limits to ensure that no possible default setting, incorrectly operating relays, etc. will occur when needed. Note such trips have been found, along with identifying incorrect relay, meter, and readings.

3. Allowing plants to better understand their operations (e.g., reactive power output). During testing site personnel who often do not deal with or significantly understand reactive power output are permitted to see how the unit can operate under such conditions so that they are better prepared in case of grid critical conditions.

MOD-025-2 Statistical Results and Analysis

The following statistical data was compiled for analysis by a large utility at the completion of the MOD-025-2 July 1st, 2019 deadline. As described below, the information collected shows that MOD-025-2 does not meet its intended objective for demonstration of the generators’ reactive capability. Where possible, adjacent unit(s) were utilized to aid the unit under test in obtaining its reactive capability. The generation mix consisted of nuclear, coal, natural gas, hydro, solar, wind, and biomass units. Transmission voltages were allowed to vary within a maximum range during testing per regional transmission policies.

Figure 4 shows that 897 tests were performed on 261 generators. Less than 10% of the tests demonstrated the generators reactive “D curve” capability, due to various limits encountered during the tests. Not one generator successfully achieved its “D curve” reactive capability and UEL limiter for all tests. Figures 5 and 6 categorize the results by test. Although slightly better results were achieved in reactive power production, the results fall short of the desired objective. Figures 7 and 8 summarize the limiting factors for each test category. In all cases, the generator terminal voltage limits were the predominant limiting factor, followed by the AVR UEL, station service auxiliary bus voltage limits, and transmission system voltage limits.

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9 Those ranges were typically +/- 1 kV for 115kV, +/- 2kV for 230kV and +/- 4kV for 500kV system voltages.
10 Tests that encountered field current limits could qualify as achieving the actual capability so long as engineering calculations are performed as described in Figure 3.
11 For entities that are not vertically integrated, identification of optimized station service tap settings and other operational constrains are more common. However, these are not related to verification of generator capability (the purpose of MOD-025-2).
MOD-025-2 Results Summary

- 83 total number of tests achieving reactive capability
- 814 total number of tests NOT achieving reactive capability
- 897 total number of tests
- 261 total number of generators tested
- 9.3% Generators achieving reactive capability
- 90.7% Generators NOT achieving reactive capability
- 100.0%

Figure 4: Summary of MOD-025-2 Testing
**Figure 5: Pmax / Qmax and Pmax / Qmin Test Results**

<table>
<thead>
<tr>
<th>Test results summary for Pmax/Qmax</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Generators achieving reactive capability</td>
<td>54</td>
</tr>
<tr>
<td>Generators NOT achieving reactive capability</td>
<td>207</td>
</tr>
<tr>
<td>Total units</td>
<td>261</td>
</tr>
</tbody>
</table>

**Figure 6: Pmin / Qmax and Pmin / Qmin Test Results**

<table>
<thead>
<tr>
<th>Test results summary for Pmin/Qmax</th>
<th></th>
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<tbody>
<tr>
<td>Generators achieving reactive capability</td>
<td>26</td>
</tr>
<tr>
<td>Generators NOT achieving reactive capability</td>
<td>171</td>
</tr>
<tr>
<td>Total units</td>
<td>197</td>
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</tbody>
</table>

<table>
<thead>
<tr>
<th>Test results summary for Pmin/Qmin</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Generators achieving reactive capability</td>
<td>0</td>
</tr>
<tr>
<td>Generators NOT achieving reactive capability</td>
<td>197</td>
</tr>
<tr>
<td>Total units</td>
<td>197</td>
</tr>
</tbody>
</table>
### Test results summary for Pmax/Qmax in descending order

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<thead>
<tr>
<th>Rank</th>
<th>Limiting Factor</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>63</td>
<td>Generator upper voltage limit</td>
<td>30.4%</td>
</tr>
<tr>
<td>35</td>
<td>Station Service Aux bus upper voltage limit</td>
<td>16.9%</td>
</tr>
<tr>
<td>34</td>
<td>Transmission bus upper voltage limit</td>
<td>16.4%</td>
</tr>
<tr>
<td>27</td>
<td>Generator Over Excitation Limiter (OEL)</td>
<td>13.1%</td>
</tr>
<tr>
<td>20</td>
<td>Generator field current</td>
<td>9.3%</td>
</tr>
<tr>
<td>8</td>
<td>Reached facility Controller PQI PF Limit</td>
<td>3.9%</td>
</tr>
<tr>
<td>7</td>
<td>Administrative operational limit restriction</td>
<td>3.4%</td>
</tr>
<tr>
<td>6</td>
<td>Generator Stator current limit</td>
<td>2.9%</td>
</tr>
<tr>
<td>4</td>
<td>Generator cold gas temperature alarms</td>
<td>1.3%</td>
</tr>
<tr>
<td>1</td>
<td>Generator Excitation System VFLc limiter</td>
<td>0.5%</td>
</tr>
<tr>
<td>1</td>
<td>Inverter Controls Limit</td>
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<tr>
<td>1</td>
<td>34.5kV Bus Upper Voltage Limit</td>
<td>0.5%</td>
</tr>
</tbody>
</table>

Total: 207 check 100.0%

### Test results summary for Pmax/Qmin in descending order

<table>
<thead>
<tr>
<th>Rank</th>
<th>Limiting Factor</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>106</td>
<td>Generator lower voltage limit</td>
<td>44.4%</td>
</tr>
<tr>
<td>87</td>
<td>Generator Under Excitation Limiter (UEL or MEL)</td>
<td>36.4%</td>
</tr>
<tr>
<td>15</td>
<td>Generator Stator current limit</td>
<td>6.3%</td>
</tr>
<tr>
<td>14</td>
<td>Transmission bus lower voltage limit</td>
<td>5.9%</td>
</tr>
<tr>
<td>8</td>
<td>Station Service Aux bus lower voltage limit</td>
<td>3.3%</td>
</tr>
<tr>
<td>8</td>
<td>Administrative operational limit restriction</td>
<td>3.3%</td>
</tr>
<tr>
<td>1</td>
<td>Unit tipped</td>
<td>0.4%</td>
</tr>
</tbody>
</table>

Total: 239 check 100.0%

---

Figure 7: Pmax / Qmax and Pmax / Qmin Test Limiting Factors

---

12 Tests that encountered UEL or MEL, as well as those reaching the generator stator current limit could qualify as achieving the actual capability so long as engineering calculations are performed (although this is not required in MOD-025-2).
Tests that encountered UEL or MEL, as well as those reaching the generator stator current limit, could qualify as achieving the actual capability so long as engineering calculations are performed (although this is not required in MOD-025-2).
MOD-025-2 Cost Results and Analysis

Figure 9 summarizes the personnel costs associated with performing MOD-025-2 testing for 261 generators for one Generator Owner.\textsuperscript{14} Not captured is the forgone cost of shifting the optimization of generation fleet assets due to minimum load testing requirements. Anytime a baseload generator is restricted in output, its output is often replaced with a generator that has a higher cost per MWh to operate.

<table>
<thead>
<tr>
<th>Department</th>
<th>Personnel</th>
<th>Scope of Work (SOW) Responsibilities</th>
<th>Hours</th>
<th>Cost</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>ERO - Support</td>
<td>Principal</td>
<td>Coordinate testing schedule with applicable entities, prepare test procedures, prepare test report forms, prepare unit electrical limits</td>
<td>5001</td>
<td>$550,063</td>
<td>Hours were determined as constituting 60% of the ERO engineers annual worked hours of 2000 hours over the 5.5 year</td>
</tr>
<tr>
<td></td>
<td>Engineer</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Electrical Field Support</td>
<td>Lead Site</td>
<td>Assist plant operations in performing tests and gathering data for submission to the ERO Support group</td>
<td>1680</td>
<td>$184,800</td>
<td>Hours were determined as 2 hours travel to and from plant site, 2 hours for Pfi/Qmax and 1 hour for all other tests.</td>
</tr>
<tr>
<td></td>
<td>Engineer</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Sr. Engineer</td>
<td>Assist plant operations in performing tests and gathering data for submission to the ERO Support group</td>
<td>1680</td>
<td>$161,280</td>
<td>Hours were determined as 2 hours travel to and from plant site, 2 hours for Pfi/Qmax and 1 hour for all other tests.</td>
</tr>
<tr>
<td>Bulk Power Operations</td>
<td>Principal</td>
<td>Perform transmission system stabilities studies for risk assessment to system when performing the tests</td>
<td>897</td>
<td>$98,670</td>
<td>Hours were determined per category of test. 1 hour used as base.</td>
</tr>
<tr>
<td></td>
<td>Engineer</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fleet Optimization</td>
<td>Project</td>
<td>Schedule units for test and arrange alternative generating resource to cover for minimum loading testing. Schedule units that are not</td>
<td>224</td>
<td>$24,668</td>
<td>Hours were determined per category of test. 0.25 hours used as base.</td>
</tr>
<tr>
<td></td>
<td>Manager</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Transmission Planner</td>
<td>Principal</td>
<td>Evaluate MOD-025-2 reported test results</td>
<td>112</td>
<td>$12,334</td>
<td>Hours were determined per category of test. 0.125 hours used as base.</td>
</tr>
<tr>
<td></td>
<td>Engineer</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Plant Operations (local or remote)</td>
<td>Plant</td>
<td>Perform necessary tasks to operate generator for tests</td>
<td>1158</td>
<td>$97,272</td>
<td>Hours were determined as 2 hours for Pfi/Qmax and 1 hour for all other tests.</td>
</tr>
<tr>
<td></td>
<td>Operator</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

\begin{tabular}{|c|c|c|c|}
\hline
Total Hrs & 10752 & $1,129,086 & Total Cost \\
\hline
Total Tests & 897 & $1,259 & Cost per test \\
\hline
Total Generators & 261 & $4,326 & Cost per generator \\
\hline
\end{tabular}

**Figure 9: MOD-025-2 Personnel Cost Analysis**

**Recommendation**

Raw data collected as part of testing performed for MOD-025-2 should not be directly used for representing generating resources (or synchronous condensers) in system planning study models. The NERC PPMVTF recommends that the existing MOD-025-2 standard be either altered or withdrawn and replaced with a new standard entirely.\textsuperscript{15} The NERC PPMVTF recommends that a SAR be developed, and a SDT be created to address these issues with MOD-025-2.

Changes are needed to MOD-025-2 to prevent inaccurate data from being used to represent generating resources (and synchronous condensers) in the transmission planning models. The PPMVTF believes that

\textsuperscript{14} Anecdotally, other entities report substantially higher costs per unit for completing MOD-025-2. This data reflects one entity, and may not be representative of the average costs across all GOs.

\textsuperscript{15} A minority opinion in NERC PPMVTF is that MOD-025-2 should be withdrawn and not replaced with another standard.
there is value in performing the tests since they can uncover unexpected limiting factors; however, the PPMVTF agrees that the data acquired during MOD-025-2 testing should not be directly used to represent the actual capability of the machine in power system models. Therefore, the tests do not generally accomplish the stated purpose of the standard.
Reliability Guideline:  *BPS Perspectives for Implementing IEEE 1547-2018*

**Action**

Approve

**Background**

The NERC Planning Committee (PC) identified key points of interest that should be addressed related to a growing penetration of distributed energy resources (DER) and established the System Planning Impacts of Distributed Energy Resources Working Group (SPIDERWG). The SPIDERWG’s approved scope includes providing technical recommendations for the adoption and use of IEEE Std 1547™-2018 *Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces*.

Published in April 2018, IEEE 1547-2018 significantly enhances performance and functional capability of DER connecting specifically to primary and secondary distribution systems. IEEE 1547-2018 is intended to apply only to DER connected to the distribution system, and is generally not suited for other interconnection levels (i.e., resources connecting to the subtransmission or transmission systems). However, new capabilities specified in IEEE 1547-2018 align with BPS reliability needs and present opportunities for maintaining or improving BPS reliability with increasing penetration of DERs. The attached Reliability Guideline in development by SPIDERWG discusses the adoption of IEEE 1547-2018 and considerations that should be made during its adoption that reflect BPS reliability perspectives.

The Reliability Guideline provides high-level guidance and BPS reliability perspectives that should be considered during the adoption and implementation of IEEE 1547-2018. Specifically, the guideline focuses on issues pertaining to DER that have been identified by SPIDERWG as potentially having an impact to the BPS. The guidance is intended for state regulatory staffs, Distribution Providers (DPs), Balancing Authorities (BAs), Reliability Coordinators (RCs), and other entities navigating adoption of IEEE 1547-2018 and its requirements. Each of the capability requirements and functional settings require coordination with the RC for their area. The Reliability Guideline will address key clauses in IEEE 1547-2018 in detail to ensure that BPS reliability perspectives and recommended considerations are made clear. These include, but are not limited, the following: voltage and frequency mandatory trip settings, ride-through capability, DER enter service and return to service operation, DER controls configuration, and interoperability and local DER communication interface considerations.

In December 2019, the PC authorized NERC staff to post the draft guideline for 45-day comment period. SPIDERWG has reviewed all comments developed revisions in the attached reliability guideline. All comments and SPIDERWG responses are posted on the PC reliability guidelines web page here. During the PC meeting, SPIDERWG will discuss the comments that were received and the changes that SPIDERWG made to the guideline to address comments.

Proposed motion language, if applicable:

“I move to approve the Reliability Guideline.”
Reliability Guideline
Bulk Power System Reliability Perspectives on the Adoption of IEEE 1547-2018
March 2020
# Table of Contents

Preface ........................................................................................................................................................................... iii  
Preamble ........................................................................................................................................................................ iv  
Executive Summary ......................................................................................................................................................... v  
Introduction .................................................................................................................................................................. vii  

Potential Impacts of DER on BPS Reliability .............................................................................................................. vii  
Background of IEEE 1547-2018 ................................................................................................................................ viii  
Implementation of IEEE 1547-2018.......................................................................................................................... viii  
Coordination between Distribution and Transmission Entities.................................................................................. xi  

Chapter 1 : BPS Perspectives on IEEE 1547-2018 Clauses .............................................................................................. 1  
Clause 1.4 – General Remarks ..................................................................................................................................... 1  
Clauses 6.4.1 and 6.4.2 – Voltage Mandatory Tripping and Ride-Through ................................................................. 3  
Clause 6.4.1 – Mandatory Voltage Tripping Requirements ..................................................................................... 4  
Clause 6.4.2 – Voltage Disturbance Ride-Through Requirements ........................................................................... 5  
Clauses 6.5.1 and 6.5.2 – Frequency Mandatory Tripping and Ride-Through ............................................................ 7  
Clause 6.5.1 – Mandatory Frequency Tripping Requirements ................................................................................ 7  
Clause 6.5.2 – Frequency Disturbance Ride-Through Requirements ...................................................................... 8  
Clause 6.4.2.7 – Restore Output .................................................................................................................................. 9  
Clause 6.5.2.7 – Frequency-Droop ............................................................................................................................ 10  
Clause 6.5.2.7.1 – Frequency-Droop Capability ..................................................................................................... 11  
Clause 6.5.2.7.2 – Frequency-Droop Operation .................................................................................................... 12  
Clause 6.5.2.8 – Inertial Response ......................................................................................................................... 13  
Clause 6.5.2.6 – Voltage Phase Angle Changes Ride-Through .................................................................................. 13  
Clause 4.10 and Clause 6.6 – Enter Service and Return to Service ........................................................................... 14  
Clause 8.1 – Unintentional Islanding ......................................................................................................................... 15  
Clause 8.2 – Intentional Islanding ............................................................................................................................. 16  
Clause 10 – Interoperability, Information Exchange, and Protocols ......................................................................... 16  

**Appendix A** : References ........................................................................................................................................... 18  
**Appendix B** : Ride-Through Requirements in IEEE 1547-2018 ................................................................................. 21  
**Appendix C** : Definitions used in IEEE 1547-2018 ..................................................................................................... 23  
Contributors .................................................................................................................................................................. 25
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is divided into six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.
Preamble

It is in the public interest for NERC to develop guidelines that are useful for maintaining or enhancing the reliability of the Bulk Electric System (BES). The NERC technical committees (the Operating Committee (OC), the Planning Committee (PC), and the Critical Infrastructure Protection Committee (CIPC)) are authorized per, their charters,\(^1\) by the NERC Board of Trustees (Board) to develop reliability (OC and PC) and security guidelines (CIPC). These guidelines establish a voluntary code of practice on a particular topic for consideration and use by BES users, owners, and operators. These guidelines are coordinated by the technical committees and include the collective experience, expertise, and judgment of the industry. The objective of this reliability guideline is to distribute key practices and information on specific issues critical to maintaining the highest levels of BES reliability. Reliability guidelines are not to be used to provide binding norms or create parameters by which compliance to standards is monitored or enforced. While the incorporation of guideline practices are strictly voluntary, reviewing, revising, or developing a program using these practices is highly encouraged to promote and achieve the highest levels of reliability for the BES.

NERC, as the FERC certified ERO,\(^2\) is responsible for the reliability of the BES and has a suite of tools to accomplish this responsibility, including, but not limited to, lessons learned, reliability and security guidelines, assessments and reports, the Event Analysis Program, the Compliance Monitoring and Enforcement Program, and mandatory reliability standards. Each entity— as registered in the NERC compliance registry—is responsible and accountable for maintaining reliability and compliance with the mandatory standards to maintain the reliability of their portions of the BES. Entities should review this guideline in detail in conjunction with the periodic review of their internal processes and procedures and make any needed changes to their procedures based on their system design, configuration, and business practices.

\(^1\) http://www.nerc.com/comm/OC/Related%20Files%20DL/OC%20Charter%2020131011%20(Clean).pdf

NERC has been focusing on ensuring reliable operation of the BPS under increasing penetrations of BPS-connected inverter-based resources as well as distributed energy resources (DERs). The NERC Integrating Variable Generation Task Force (IVGTF) also stated that large amounts of DERs connected to the grid could have significant effects on reliability of the BPS. Of main concern was the lack of disturbance ride-through capability. The NERC Distributed Energy Resources Task Force (DERTF) report further characterized the impacts that DER may have on BPS reliability. Recent BPS disturbances have illustrated the need for fault ride-through capability, particularly the need for voltage phase angle jump ride-through and rate-of-change-of-frequency ride-through capability. Lastly, the NERC Load Modeling Task Force (LMTF) developed a modeling framework and recommended adopting practices for studying the aggregate impacts that DER may have on the BPS. The NERC System Planning Impacts of Distributed Energy Resources Working Group (SPIDERWG) is further analyzing these impacts and developing recommended practices and industry guidance.

IEEE Std 1547™-2018 Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces, (referred to herein as “IEEE 1547-2018”), was published in April 2018 and significantly enhances performance and functional capability of DER connecting specifically to primary and secondary distribution systems. IEEE 1547-2018 is intended to apply only to DER connected to the distribution system, and is generally not suited for other interconnection levels (i.e., resources connecting to the subtransmission or transmission systems). These new capabilities align with the BPS reliability needs, and present opportunities for maintaining or improving BPS reliability with increasing penetration of DERs. The IEEE P1547.1 working group expects equipment certified to this new standard to become available in the 2021 timeframe. This Reliability Guideline discusses the adoption of IEEE 1547-2018 and considerations that should be made during its adoption that reflect BPS reliability perspectives.

The timely adoption and implementation of IEEE 1547-2018 for DER connected to the distribution system across North America is strongly encouraged. The specifications for DER in IEEE 1547-2018 include performance capability categories and allowable ranges of functional settings, which provide flexibility to align with specific system needs. However, these flexibilities require coordination between distribution and transmission entities for effective adoption. The adoption of IEEE 1547-2018 requires the Authority Governing Interconnection Requirements (AGIR) and various stakeholders to get involved at a deeper technical level than in the past. Due to the required amount of coordination in IEEE 1547-2018, it is expected that AGIRs may need around two years to effectively develop an implementation plan for the standard. Further, DERs compliant with IEEE 1547-2018 are expected to become readily available in 2021, and this is a key incentive for AGIRs to begin the coordination activities for adoption and implementation of the standard.

---


5 Refer to the definition of DER provided in IEEE 1547-2018. Also refer to the NERC DERTF definition of DER, defined as “any resource on the distribution system that produces electricity and is not otherwise included in the formal NERC definition of the BES.” Note, however, that generating resources connected to the sub-transmission system should generally be classified as BPS-connected and not as DER. This applies in this paper.

6 This entails voltage ride-through (VRT) and frequency ride-through (FRT) capability.


10 Per IEEE 1547-2018, the Authority Governing Interconnection Requirements (AGIR) may be a regulatory agency, public utility commission, municipality, cooperative board of directors, etc.

This Reliability Guideline provides high-level guidance and BPS reliability perspectives that should be considered during the adoption and implementation of IEEE 1547-2018. Specifically, the guideline focuses on issues pertaining to DER that have been identified by NERC SPIDERWG as potentially having an impact to the BPS. The guidance provided herein is intended particularly to support state regulatory staffs in their adoption and implementation of IEEE 1547-2018, as the entity most likely to fill the role of the Authority Governing Interconnection Requirements (AGIR) in many cases. The materials presented will likely aid AGIRs in coordinating with Distribution Providers (DPs), Balancing Authorities (BAs), Reliability Coordinators (RCs), and other entities navigating adoption of IEEE 1547-2018 and its requirements. Each of the capability requirements and functional settings require coordination with the RC for their area. This Reliability Guideline will address key clauses in IEEE 1547-2018 in detail to ensure that BPS reliability perspectives and recommended considerations are made clear. These include, but are not limited, the following: voltage and frequency mandatory trip settings, ride-through capability, DER enter service and return to service operation, DER controls configuration, and interoperability and local DER communication interface considerations.

---

12 Readers are encouraged to become familiar with IEEE 1547-2018 in its entirety which goes beyond BPS-related issues. Be aware that IEEE 1547 is subject to change. For example, since IEEE 1547-2018 was approved, the IEEE Standards Association has issued an errata for IEEE 1547-2018 in June 2018 and has also approved a Project Authorization Request in September 2019 for an amendment to the standard.

13 The term Authority Governing Interconnection Requirements is introduced in IEEE 1547-2018, and in most cases is likely the state regulatory utility commission.

14 IEEE 1547-2018 specifies the term ‘regional reliability coordinator’ as the functional entity that maintains the real-time operating reliability of the BPS within an RC area. This is synonymous with the term RC as defined in the NERC Functional Model. Refer to the NERC website for a map of RC footprints: https://www.nerc.com/pa/rrm/TLR/Pages/Reliability-Coordinators.aspx.
**Introduction**

This guideline provides BPS perspectives that should be considered during the adoption and implementation of IEEE 1547-2018 [1][2]. It does not cover every specific clause of IEEE 1547-2018; however, it addresses general benefits of the standard and specific clauses related to BPS reliability. This guideline is not intended to suffice as engagement or coordination among RCs and other stakeholders nor intended to address regionally-specific consideration; rather, it is intended to serve as a useful reference in these coordination activities. Note that the use of terminology generally mirrors the definitions of IEEE 1547-2018; refer to Appendix C for definitions of terms used.

**Potential Impacts of DER on BPS Reliability**

At low penetration levels, DERs may not pose a significant risk to BPS reliability. However, as the penetration continues to increase across many parts of North America, the aggregate effects of DER present both challenges and opportunities for planning, design, and operation of the BPS. NERC has been analyzing the impacts that DERs can have on the BPS [3]. Key findings and recommendations from this initial work have been documented in the NERC Integrating Variable Generation Task Force (IVGTF) report15 and the NERC Distributed Energy Resources Task Force (DERTF) report [4].16 These efforts, and ongoing work by the NERC System Planning Impacts of Distributed Energy Resources Working Group (SPIDERWG), are focusing on the aggregate impact that DER can have on BPS reliable operation. Of particular focus are the following areas:

1. The impacts that DERs have by offsetting gross load, resulting in the displacement of BPS generation which are providing various essential reliability services (ERSs).
2. The impacts that DERs have on balancing generation and demand, and ensuring that BAs are carrying a sufficient amount of resources to meet ramping requirements.
3. The ability of the BPS to have adequate levels of voltage regulation and reactive power support with increasing penetration of DERs.
4. The impacts that legacy DER ride-through and trip settings may have on BPS performance following large disturbances.
5. The ability to model and forecast DER for the purposes of planning and operations studies.
6. The ability to ensure BPS reliability with increasing amounts of generation that are not currently observable17 or dispatchable.

The aggregate effect of many DERs distributed across the interconnected BPS is already having an impact on BPS planning and operations. For example, the California Energy Commission (CEC) Integrated Energy Policy Report (IEPR) forecasts approximately 6845 MW of DER within the California Independent System Operator (CAISO) footprint.18 In response to their concerns about DER, the California Public Utility Commission adopted CA rule 21,19 which identified and implemented many of the functional capabilities that are now included in IEEE 1547-2018 and mandated that all solar PV DER installed starting September 9, 2017 use “smart inverters” to provide grid support and help address the issues described above. Thousands of MWs of DER have been installed in California since that time with smart inverter functionality mandated by CA Rule 21. However, much of the installed equipment (i.e., legacy equipment) that could 

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17 The inability for BPS grid planners and operators to understand the DER location, equipment standardization, on-line performance and behavior to grid events may pose significant challenges in both planning and operational time horizons and will increase in severity as the penetration of DERs continues to increase.
18 https://www.energy.ca.gov/2019_energy_policy/
19 https://www.cpuc.ca.gov/Rule21/
trip rather than ride through disturbances (since it predates the update to CA Rule 21) still remains and will likely remain for decades.

**Background of IEEE 1547-2018**

IEEE 1547-2018 is a newly published IEEE standard that specifies minimum technical interconnection and interoperability requirements for DERs connected to the distribution system \[1\].\(^{20}\) Changes in the -2018 version of the standard address issues in the original -2003 version or needed change due to present technology developments and recent learnings \[2\].\(^{21}\) At a high level, the new standard introduces five key elements:

1. It expands the scope of the prior IEEE 1547 standard by considering BPS issues, such as ride-through requirements, as well as distribution system issues.\(^{22}\)

2. It extends requirements from the interconnection system and the individual DER unit to the whole DER facility (i.e., DER system). For example, DER auxiliary equipment will now be capable of withstanding specified voltage and frequency disturbances.

3. It expands the applicability beyond individual equipment such that it can be used for plant-level verification.

4. It specifies capabilities and functions necessary in a local DER communication interface (e.g. interoperability considerations) in addition to the electrical performance of the DER at its connection point.\(^{23}\)

5. It enables DER to have the capability of providing autonomous response to voltage and frequency changes to support the grid, including voltage regulation and frequency-droop response.

Other new requirements include prioritization of DER functions, measurement accuracy requirements, and power quality requirements. IREC published a review of changes in the -2018 version for state regulators \[5\] and NRECA published a guide for cooperative utility engineers \[6\]. The Electric Power Research Institute (EPRI) reviewed experience with the standard’s implementation to date \[7\] and has published materials related to BPS issues as well \[8\], \[9\], \[10\].

**Implementation of IEEE 1547-2018**

IEEE 1547-2018 is intended to apply only to DER connected to the distribution system, and is generally not suited for other interconnection levels (i.e., resources connecting to the subtransmission or transmission systems).\(^{24}\) BPS-connected inverter-based resources should follow the recommendations set forth by NERC,\(^{25}\) are required to meet local utility interconnection requirements,\(^{26}\) and are expected to be required to meet the requirements being developed by IEEE P2800 which is the transmission counterpart to IEEE 1547.\(^{27}\) IEEE 1547-2018 is technology-neutral and was vetted by a large group of industry stakeholders ranging from DER manufacturers to distribution and transmission utilities. The goal of IEEE 1547-2018 implementation is to harmonize technical interconnection

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\(^{21}\) http://sites.ieee.org/sagroups-scc21/standards/1547rev/.

\(^{22}\) For example, lack of ride-through capability can have a negative impact on BPS reliability. This was observed in the Palmdale Roost and Angeles Forest disturbances in North America and it the August 2019 disturbance that occurred in the United Kingdom: https://www.nerc.com/pa/rrm/ea/Pages/April-May-2018-Fault-Induced-Solar-PV-Resource- Interruption-Disturbances-Report.aspx


\(^{23}\) Once communications networks are deployed, utilities or aggregators can communicate with this interface to monitor, control, and exchange information with DER.

\(^{24}\) The NERC Inverter-Based Resource Performance Task Force (IRPTF) identified misapplication of IEEE 1547 for BPS-connected inverter-based resources due to the linkage of IEEE 1547 with the interrelated UL 1741 Standard: https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf


\(^{27}\) https://standards.ieee.org/project/2800.html.
performance capability requirements and functional specifications for the growing installations of DER. Development of IEEE 1547-2018 considered different regional and utility-specific situations as well as the current and anticipated future capabilities of the technology to safely and reliably interconnect DER to the grid.

Entities will need to ensure that updates to interconnection requirements and implementation of IEEE 1547-2018 aligns with the roll-out of equipment compliant with the standard.

**Authority Governing Interconnection Requirements**

IEEE standards are voluntary in nature, and therefore must be adopted by state regulators, local distribution utilities, or other applicable governing bodies throughout North America. The Federal Energy Regulatory Commission (FERC) Small Generator Interconnection Procedures (SGIP) and Energy Policy Act of 2005 reference IEEE 1547 and any updates to the standard; therefore, DERs whose interconnections are subject to FERC jurisdiction are likely subject to the requirements of IEEE 1547-2018. Similarly, AGIRs should ensure appropriate adoption and implementation of IEEE 1547-2018 in interconnection requirements for all other DERs not subject to FERC jurisdiction. In many cases, interconnection requirements for DERs may need to be modified to accommodate the new standard.

In February 2020, the National Associations of Regulatory Utility Commissioners (NARUC) approved a resolution recommending state utility commissions adopt and implement IEEE 1547-2018. The resolution grants flexibility for state commissions recognizing the unique procedures, priorities and needs for each state; while recognizing the best practices identified by technical experts and IEEE 1547-2018 for convening a stakeholder process, utilizing existing research and experience to make evidence-based decisions and aligning the implementation of the standard with the availability of certified equipment.

IEEE 1547-2018 includes performance categories and functional settings that allow significant flexibility; however, selecting the appropriate settings requires stakeholder involvement. The standard introduces the concept of the Authority Governing Interconnection Requirements (AGIR), which is defined in IEEE 1547-2018 as:

**Authority Governing Interconnection Requirements (AGIR):** A cognizant and responsible entity that defines, codifies, communicates, administers, and enforces the policies and procedures for allowing electrical interconnection of DER to the Area Electric Power System (EPS). This may be a regulatory agency, public utility commission, municipality, cooperative board of directors, etc. The degree of AGIR involvement will vary in scope of application and level of enforcement across jurisdictional boundaries. This authority may be delegated by the cognizant and responsible entity to the Area EPS operator or bulk power system operator.

As stated, an AGIR can be a state regulator or a municipal or cooperative governing board. DPs should be aware that a high degree of technical involvement is necessary for successfully implementing IEEE 1547-2018. Additionally, coordination across many stakeholders is also necessary. Reliability Coordinators (RCs), Planning Coordinators (PCs), Transmission Planners (TPs), Transmission Owners (TOs), Transmission Operators (TOPs), Balancing Authorities (BAs), state regulatory agencies, manufacturers, and developers will likely all have a stake in how IEEE 1547-2018 is implemented for each local jurisdiction. Collaboration at the state-level and regional-level are encouraged to engage all necessary stakeholders. The goal is that involvement from all interested stakeholders will lead the state regulatory entities and DPs to successful selection of appropriate settings within IEEE 1547-2018 and appropriate enforcement of the standard across all DER connecting to their grid.

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28 Including distributed generation and energy storage systems.
29 https://site.ieee.org/sagroups-scc21/standards/1547rev/
30 https://pubs.naruc.org/pub/4C436369-155D-0A36-314F-8B6C4DE0F7C7
32 IEEE 1547-2018 also states: “NOTE—Decisions made by an authority governing interconnection requirements should consider various stakeholder interests, including but not limited to Load Customers, Area EPS operators, DER operators, and bulk power system operator.”
It is expected that this process of reaching consensus between all interested parties regarding assigning voltage and frequency ride-through performance categories and determining regional voltage and frequency trip setting (thresholds and clearing times) can take around two years. Utilizing DER communication and interoperability capabilities will also require a significant amount of coordination, and may require updates to technical interconnection and interoperability requirements to address customer privacy and contractual concerns. Relevant entities, including state regulatory entities, are encouraged to support early implementation of IEEE 1547-2018 and begin engaging with necessary stakeholders. DERs that are fully certified to comply with IEEE 1547-2018 are expected to be widely available to commercial markets in 2021. AGIRs should initiate the stakeholder process early such that full implementation can align with the availability of certified equipment. AGIRs with an existing high penetration of DERs may consider earlier interim implementation dates similar to what regions such as California (Rule 21), Hawai’i (Rule 14h), and others have done; however, note such interim implementation requires specific considerations to ensure eventual alignment with IEEE 1547-2018. Table I.1 presents a summarized comparison of the different requirements between California Rule 21, Hawai’i Rule 14h, and the new IEEE 1547-2018.

### Table I.1 Comparison between IEEE 1547 and other DER Interconnection Standards

[Source: EPRI]

<table>
<thead>
<tr>
<th>Standards for DER</th>
<th>Listing/Certification</th>
<th>Interconnection Standards</th>
<th>State/PUC/Utility Rules</th>
</tr>
</thead>
<tbody>
<tr>
<td>Function Set</td>
<td>UL 1741</td>
<td>IEEE 1547.1</td>
<td>IEEE 1547-2003</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Rule 21 (Phases)</td>
<td>Rule 14H &amp; UL SRDv1.1</td>
</tr>
<tr>
<td>All</td>
<td>Δ</td>
<td>α</td>
<td>α</td>
</tr>
<tr>
<td>Monitoring &amp;</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Control</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ramp Rate Control</td>
<td>α</td>
<td>α</td>
<td>α</td>
</tr>
<tr>
<td>Communication Interface</td>
<td>Δ</td>
<td>α</td>
<td>α</td>
</tr>
<tr>
<td>(Remote Shut-Off, Remote Disconnect/Reconnect)</td>
<td>Δ</td>
<td>α</td>
<td>α</td>
</tr>
<tr>
<td>Limit Active Power</td>
<td>Δ</td>
<td>α</td>
<td>α</td>
</tr>
<tr>
<td>Monitor Key DER Data</td>
<td>Δ</td>
<td>α</td>
<td>α</td>
</tr>
<tr>
<td>Scheduling</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Set Active Power</td>
<td>Δ</td>
<td>α</td>
<td>α</td>
</tr>
<tr>
<td>Reactive Power</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Constant Power Factor</td>
<td>α</td>
<td>α</td>
<td>α</td>
</tr>
<tr>
<td>Voltage-Reactive Power (Volt-Var)</td>
<td>Δ</td>
<td>α</td>
<td>α</td>
</tr>
<tr>
<td>Autonomously Adjustable Voltage Reference</td>
<td>Δ</td>
<td>α</td>
<td>α</td>
</tr>
<tr>
<td>Active Power-Reactive Power (Watt-Var)</td>
<td>Δ</td>
<td>α</td>
<td>α</td>
</tr>
<tr>
<td>Constant Reactive Power</td>
<td>α</td>
<td>α</td>
<td>α</td>
</tr>
<tr>
<td>Voltage-Active Power (Volt-Watt)</td>
<td>α</td>
<td>α</td>
<td>α</td>
</tr>
<tr>
<td>Dynamic Voltage Support during VR</td>
<td>α</td>
<td>α</td>
<td>α</td>
</tr>
<tr>
<td>Rate-of-Change-of-Frequency Ride-Through</td>
<td>Δ</td>
<td>Δ</td>
<td>Δ</td>
</tr>
<tr>
<td>Voltage Ride-Through (VRT)</td>
<td>Δ</td>
<td>Δ</td>
<td>Δ</td>
</tr>
<tr>
<td>Voltage Phase Angle Jump Ride-Through</td>
<td>Δ</td>
<td>Δ</td>
<td>Δ</td>
</tr>
<tr>
<td>Return to Service (Enter Service)</td>
<td>Δ</td>
<td>Δ</td>
<td>Δ</td>
</tr>
<tr>
<td>Bulk System</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Reliability</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Rate-of-Change-of-Frequency Ride-Through</td>
<td>Δ</td>
<td>Δ</td>
<td>Δ</td>
</tr>
<tr>
<td>Voltage Ride-Through (VRT)</td>
<td>Δ</td>
<td>Δ</td>
<td>Δ</td>
</tr>
<tr>
<td>Voltage Phase Angle Jump Ride-Through</td>
<td>Δ</td>
<td>Δ</td>
<td>Δ</td>
</tr>
<tr>
<td>Frequency-Watt</td>
<td>Δ</td>
<td>Δ</td>
<td>Δ</td>
</tr>
<tr>
<td>Anti-Islanding Detection and Trip</td>
<td>Δ</td>
<td>Δ</td>
<td>Δ</td>
</tr>
<tr>
<td>Other Advanced DER Functions</td>
<td>Δ</td>
<td>Δ</td>
<td>Δ</td>
</tr>
<tr>
<td>Return to Service (Enter Service)</td>
<td>Δ</td>
<td>Δ</td>
<td>Δ</td>
</tr>
</tbody>
</table>

Legend: X Prohibited, V Allowed by Mutual Agreement, Δ Capability Required, α Test and Verification Defined
[... ] Subject to clarification of the technical requirements and use cases, !!! Important Gap

IEEE P1547.2 Working Group is drafting an Application Guide for IEEE 1547-2018 that will include additional information for effective implementation of IEEE 1547-2018. The IEEE application guide is expected to be published in the 2021–2022 timeframe. EPRI is also working with its members on a project titled Navigating DER Interconnection Standards and Practices to develop guidance on the adoption of IEEE 1547-2018 [11].

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33 Definition of trip in IEEE 1547-2018: “Inhibition of immediate return to service, which may involve disconnection. Note: Trip executes or is subsequent to cessation of energization.”
35 https://www.cpuc.ca.gov/Rule21/
Coordination between Distribution and Transmission Entities

IEEE 1547-2018 addresses the natural diverging objectives between transmission and distribution system operation by requiring coordination among DPs and RCs. While both the DPs and RCs have the same overall goal of reliable, safe, and cost-effective power system operation, they have different operational responsibilities. RCs are focused on regional and system-wide reliability, where objectives include longer DER trip times, capability of DERs to ride-through specified voltage and frequency excursions (and continue injecting active and reactive current, when possible), and also ride through large deviations in phase angle [12]. DPs are focused on shorter DER trip times and utilization of momentary cessation37 over a wider range of voltages due to safety concerns for line workers and the public regarding unintentional islanding and protection coordination. Many DPs are concerned that limited testing and certifications for DERs may not reflect actual performance during a wide variety of real-world conditions. These conflicting objectives are illustrated in Figure I.1, and can be addressed if the AGIR initiates a stakeholder process to coordinate ride-through capability requirements, regional voltage and frequency trip settings, as well as other advanced38 features. Examples of these stakeholder processes include PJM [13][14], MISO [15][16], and the Massachusetts Technical Standard Review Group [17].

Adoption of IEEE 1547-2018 requires entities to make decisions regarding how to implement the standard. Learnings from ongoing regional adoption suggest including selection of the following:

- Normal operating condition reactive power-voltage regulation (IEEE 1547-2018, Clause 5)
- Abnormal voltage and frequency ride-through performance categories (IEEE 1547-2018, Clause 6)
- Voltage and frequency regulation settings (IEEE 1547-2018, Clauses 5 and 6)
- Selection of standardized communication protocols (IEEE 1547-2018, Clause 10)

It is difficult to retrofit new capabilities into DER equipment once installed in the field. Therefore, it is critical that these decisions be made early to ensure that newly interconnecting DER have the capability and appropriate settings to meeting the functional specifications laid out in IEEE 1547-2018 (even if some of these capabilities may not yet be utilized until they become necessary at a future date).

37 Momentary cessation definition in IEEE 1547-2018: “temporarily cease to energize an EPS, while connected to the Area EPS, in response to a disturbance of the applicable voltages or the system frequency, with the capability of immediate Restore Output of operation when the applicable voltages and the system frequency return to within defined ranges.”

38 Other advanced features may include, but are not limited to, automatic voltage (volt-var) control, frequency-droop (frequency-power) control, or phase jump ride-through.
IEEE 1547-2018 provides default values for many functional settings for DER performance during normal and abnormal voltage and frequency conditions. Without further specification of functional settings beyond the specification of particular performance categories, adoption of IEEE 1547-2018 would require all jurisdictional DERs and associated interconnection equipment to utilize the category-specific default values; including whether the functionality is enabled or disabled. However, the standard also provides flexibility for the settings to be altered from default values, as needed. During the AGIR-initiated stakeholder process, and using the default values as a starting point, entities should consider whether these settings are appropriate based on DER technology, size, etc.

Ranges of adjustability and different performance category levels are provided in the standard such that regional or utility-specific settings can be established for specific Area EPS needs, Local EPS needs, and to address the capabilities of different DER technologies. Decisions relating to abnormal performance category assignment and specification of regional settings for any active power-related functions (e.g., frequency-droop and other functions not covered in this guideline such as voltage-active power) should be coordinated with the RC. Ideally, regional or minimum settings should be chosen based on regional BPS reliability studies using latest aggregate DER modeling practices [25], [26]. If DPs need to divert from regional category assignments and settings, the RC should be informed about these utility-specific settings to ensure the DER are accurately modeled in reliability studies. Figure I.2 illustrates the various levels of DER functional settings, with regional settings expected in the near term and site specific settings in the long term.

![Figure I.2: Levels of DER Interconnection Requirements and Settings [Source: EPRI]](https://dersettings.epri.com)

Management of the increasing diversity of DER functional settings can become a challenge. Even once DPs and RCs successfully coordinated DER functional settings, the reliable application of these settings to DERs in the field may not be ensured. Many DER manufacturers currently use so-called manufacturer-automated profiles (“MAPs”) that pre-set certain functional parameters to the values specified in applicable rules like CA Rule 21, HI Rule 14H, or the default values of a certain IEEE 1547-2018 performance category. To date, these MAPs are not validated by any third party and verification by utility engineers is often limited to the review of a photo, taken by a DER installer of the selected MAP on the DER’s general user interface at the time of commissioning. Given the criticality of DER trip and other settings for the BPS, more sophisticated verification methods are desired. One approach being explored by EPRI is developing a central database to store DER settings where authorized users can write settings and all other users can read these settings to help exchange information among all applicable entities [18].

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39 These may be called “utility-required profiles (URPs)” and may be implemented via “manufacturer-automated profiles (MAPs)”.

### BPS Perspectives and Recommendations

Key issues to address through coordination with the RCs include reactive power-voltage regulation during normal operations, abnormal voltage and frequency ride-through performance categories, regional voltage and frequency regulation settings, and communication protocols. Decisions relating to abnormal performance category assignment and specification of regional settings for any active power-related functions (e.g., frequency-droop and voltage-active power) should be coordinated with the RC. If DPs need to divert from regional category assignments and settings, the RC should be informed about these utility-specific settings to ensure the DER are accurately modeled in reliability studies. Reliable application and verification of DER functional settings is of increasing importance. A central database is one of various options to facilitate efficient data exchange among the DP, RC, and DER installer.
Chapter 1: BPS Perspectives on IEEE 1547-2018 Clauses

This chapter discusses the sections and clauses in IEEE 1547-2018 relevant to reliable operation of the BPS, and provides BPS perspectives that should be used by AGIRs and RCs while coordinating to determine regionally-appropriate implementation of IEEE 1547-2018.

Clause 1.4 - General Remarks
Clause 1.4, Clause 6.4.2, and Annex B of IEEE 1547-2018 describe and utilize the ride-through performance category assignment of DER. Adoption of IEEE 1547-2018 requires assigning abnormal performance categories to specific (groups of) DERs, and the coordination of regional voltage and frequency trip settings across the transmission and distribution (T&D) interface. The specification of these regional functional settings will need to balance bulk system reliability and distribution concerns. Per language in IEEE 1547-2018, DPs and AGIRs “should not determine these regional settings without coordination with the appropriate [RC]”. The abnormal performance categories are defined as follows:

- **Category I:** As described in the informative appendix of IEEE 1547-2018.

- **Category II:** Category II is based on minimal BPS reliability needs and is reasonably attainable by all DER technologies that are in common usage today. The disturbance ride-through requirements for Category I acknowledge the inherent limitations that synchronous generators have compared to inverter based systems, and are derived from the German Association of Energy and Water Industries (BDEW) guideline of 2008 for medium voltage synchronous generators that is one of the most widely applied standards in Europe. Many synchronous generator manufacturers are currently designing products to meet the requirements of this standard. Category I disturbance ride-through performance, however, is not consistent with the reliability standards imposed on BPS generation resources. High penetrations of DER having only Category I capabilities could be detrimental to BPS reliability, but limited penetration of this category would not have a material negative impact. It should be noted that penetration, with regard to BPS reliability impacts, should be measured on a regional or bulk system-wide basis, and local distribution system penetration levels are not typically of particular relevance.

- **Category III:** Category III performance covers minimum BPS reliability needs, coordinates with, and closes gaps in the existing NERC Reliability Standard PRC-024-2 which was developed to avoid adverse tripping of BPS generators during system disturbances and are attainable by inverter-based resources and possibly some other DER technologies. Additional voltage ride-through capability was specified for DERs of Category II, beyond the mandatory voltage ride-through defined by PRC-024-2 to account for the potential for fault-induced delayed voltage recovery (FIDVR) on the distribution system. IEEE 1547-2018 working group members expected that Category II might be adopted by the majority of the Authorities Governing Interconnection Requirements (AGIRs) for inverter-based DER but based on experience from stakeholder processes in PJM, MISO, and ISO NE, an amendment to IEEE 1547-2018 has been initiated to provide more flexibility to adopt Category III (see below).

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41 As described in the informative appendix of IEEE 1547-2018.
44 Synchronous interconnections, such as the Eastern Interconnection, ERCOT, WECC, are examples of bulk systems in this context.
46 Synchronous generator based DER would have to be significantly redesigned to meet Category II ride-through capabilities.
• **Category III:** Category III provides the longest duration and widest bands for voltage ride-through capabilities, which are attainable by inverter-based systems where there are expected to be very high levels of DER penetration, or where momentary cessation requirements are seen as a desirable solution for coordinating with distribution system protection and safety. This category is intended to address DER integration issues such as power quality and system overloads caused by DER tripping in local Area EPS as well as provide increased BPS reliability by further reducing the potential loss of DER during bulk system events. Prior to the initiation of an amendment to IEEE 1547-2018, Category III requirements were expected to be applied to high penetration DER systems; however with the amendment, this may no longer be the case.

Table 1.1 shows the three categories for ride-through performance capability.

<table>
<thead>
<tr>
<th>Category</th>
<th>Objective</th>
<th>Foundation</th>
</tr>
</thead>
<tbody>
<tr>
<td>I</td>
<td>Essential BPS reliability needs; reasonably achievable by all current state-of-the-art DER technologies</td>
<td>German grid code for synchronous DER</td>
</tr>
<tr>
<td>II</td>
<td>Full coordination with BPS needs</td>
<td>Based on NERC Reliability Standard PRC-024-2, adjusted for distribution voltage differences (delayed voltage recovery)</td>
</tr>
<tr>
<td>III</td>
<td>Ride-through designed for distribution support as well as BPS needs</td>
<td>Based on California Rule 21 and Hawai‘i Rule 14H</td>
</tr>
</tbody>
</table>

47 An amendment to IEEE 1547-2018 is drafted by the IEEE SA to widen the allowable ranges for voltage trip clearing times of Category III that provides more flexibility to adopt Category III. The amendment would harmonize the low value of the range of allowable trip clearing time settings for UV1 and UV2 in Category III with the values specified in Category I and II, effectively allowing to terminate DER ride-through operation by trip clearing times inside the Category III voltage ride-through capability regions. With the successful ballot and likely publication of an amendment by May 2020, Category III with modified voltage trip settings is expected to become the most common requirements for inverter-based DER.

48 There is no generally accepted definition or threshold that quantifies “very high levels” of DER penetration. The concept of “high penetration” of DER penetration should not be directly linked to distribution system backflow. Penetration of DER not exceeding load can be of significant impact on BPS performance. Also, regional or interconnection-wide penetration levels are more relevant to BPS performance.

49 Category III is similar to smart inverter requirements required in California (Rule 21) and Hawai‘i (Rule 14H).

50 Allowable undervoltage trip times in Category III of not shorter than 21 seconds for shallow (UV1) and 2 seconds for deep (UV2) voltage dips were regarded as too long by many distribution protection engineers. The amendment is expected to be published in spring 2020 along with the publication of IEEE P1547.1.


52 [https://www.cpuc.ca.gov/Rule21/](https://www.cpuc.ca.gov/Rule21/)

Clauses 6.4.1 and 6.4.2 - Voltage Mandatory Tripping and Ride-Through

The response of aggregate DERs to abnormal voltage conditions contributes to the stability of the BPS, helps ensure utility maintenance personnel and public safety, and avoids damage to connected equipment including the DER itself. Developing performance requirements for DER voltage mandatory tripping and ride-through should consider the needs of the distribution system as well as the BPS. Mandatory tripping requirements in response to the area EPS abnormal conditions was one of the key items of the original IEEE 1547-2003. These settings helped assure utilities that DERs would trip off-line when voltage and frequency were outside of normal conditions to help ensure worker safety. IEEE 1547-2018 retains that fundamental concept of tripping DERs off-line during abnormal conditions. However, the “shall trip” times have been lengthened and the ride-through thresholds have been widened to balance the needs of the BPS with those of the distribution system. Limits for mandatory voltage tripping effectively define the window for “ride-through” since these settings override all other functions. For example, for both Category I and II DER, the default values for UV2 shown in Table 1.2 state that if voltage at the DER reference point drops below 0.45 pu for 0.16 seconds, the DER must cease to energize regardless of ride-through capabilities. New criteria regarding voltage sensing accuracy are also included in IEEE 1547-2018 to better support equipment capability in meeting both mandatory tripping and ride-through requirements.

54 Definition of trip in IEEE 1547-2018: “Inhibition of immediate return to service, which may involve disconnection.” Refer to the notes identified in the definition in the standard.
55 Definition of cease to energize in IEEE 1547-2018: “Cessation of active power delivery under steady-state and transient conditions and limitation of reactive power exchange.” Refer to the notes identified in the definition in the standard and appendix B of this document for an illustrative figure and further explanation of responses to abnormal conditions like cease to energize, momentary cessation, and trip.
56 Because the standard allows for a ride-through exemption “buffer” of 0.16 second prior to the trip time, this may result in zero “effective ride-through” for voltage before 0.45 p.u.
BPS Perspectives and Recommendations

- The mandatory tripping requirements in IEEE 1547-2018 are well understood to support worker and general public safety, and equipment integrity. The “shall trip” allowable clearing time ranges have been increased significantly in IEEE 1547-2018 to enable DER to utilize their capability to ride through abnormal voltage and frequency conditions on the distribution system, typically encountered during BPS contingency events.

- Shall trip settings in IEEE 1547-2018 should be mutually agreed upon by the Area EPS operator as well as the RC to ensure both distribution system and BPS reliability needs are met. Ideally, “shall trip” settings should be chosen based on regional BPS reliability studies.

Clause 6.4.1 - Mandatory Voltage Tripping Requirements

Clause 6.4.1 states the following pertaining to mandatory voltage trip settings:

“When any applicable voltage is less than an undervoltage threshold, or greater than an overvoltage threshold, as defined in this subclause, the DER shall cease to energize the Area EPS and trip within the respective clearing time as indicated. Under and overvoltage tripping thresholds and clearing times shall be adjustable over the ranges of allowable settings...Unless specified otherwise by the Area EPS operator, default settings shall be used.”

Table 1.2 shows the Category I, II, and III mandatory trip setting default values and ranges of adjustability as defined in Tables 11–13 in IEEE 1547-2018.

<table>
<thead>
<tr>
<th>Shall Trip Function</th>
<th>Default Settings</th>
<th>Ranges of Allowable Settings</th>
</tr>
</thead>
<tbody>
<tr>
<td>Category I Shall Trip Voltage Settings</td>
<td></td>
<td></td>
</tr>
<tr>
<td>OV2</td>
<td>1.20</td>
<td>0.16</td>
</tr>
<tr>
<td>OV1</td>
<td>1.10</td>
<td>2.0</td>
</tr>
<tr>
<td>UV1</td>
<td>0.70</td>
<td>2.0</td>
</tr>
<tr>
<td>UV2</td>
<td>0.45</td>
<td>0.16</td>
</tr>
<tr>
<td>Category II Shall Trip Voltage Settings</td>
<td></td>
<td></td>
</tr>
<tr>
<td>OV2</td>
<td>1.20</td>
<td>0.16</td>
</tr>
<tr>
<td>OV1</td>
<td>1.10</td>
<td>2.0</td>
</tr>
<tr>
<td>UV1</td>
<td>0.70</td>
<td>10.0</td>
</tr>
<tr>
<td>UV2</td>
<td>0.45</td>
<td>0.16</td>
</tr>
<tr>
<td>Category III Shall Trip Voltage Settings</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Chapter 1: BPS Perspectives on IEEE 1547-2018 Clauses

### Clause 6.4.2 - Voltage Disturbance Ride-Through Requirements

Clause 6.4.2 defines the abnormal voltage ride-through requirements for Category I, II, and III resources in Tables 14–16 of IEEE 1547-2018, respectively. Figures H.7–H.9 of the standard visualize these ride-through requirements as well. Appendix B of this guideline includes the ride-through figures from IEEE 1547-2018 for reference. The following notes are useful perspectives to consider when implementing IEEE 1547-2018 based on the Clause 6.4.2 requirements:

- The Area EPS Operator, as guided by the AGIR who determines applicability of the performance categories, specifies the Category (either I, II, or III) for its system. AGIRs should ensure that appropriate categories are selected for existing and future penetration levels of DER.
- For voltage perturbations within the continuous operation region of the ride-through curves, DER must remain in operation and continue delivering available active power of magnitude at least as great as its pre-

Although the default settings for voltage trip and the default voltage threshold for ride-through operation in momentary cessation are generally applicable for most DER interconnections, there may exist specific distribution circuits where protection schemes differ from the general protection approaches assumed in developing the IEEE 1547-2018 requirements. AGIRs should consider these local distribution system protection practices when implementing IEEE 1547-2018. Distribution protection methods and overall philosophy can vary considerably from entity to entity, requiring consideration of how IEEE 1547-2018 requirements may affect existing distribution protection practices. Adjusting the momentary cessation threshold may help coordinate with existing distribution protection schemes and other safety concerns.

### BPS Perspectives and Recommendations

- AGIRs should consider local distribution system protection practices when implementing IEEE 1547-2018, and ensure that appropriate shall trip settings are determined. From a BPS perspective, shall trip clearing times should be set as long as possible while still ensuring distribution system coordination and public safety.
- The voltage-related shall trip default settings of IEEE 1547-2018 are generally set to support BPS reliability, and provide sufficient robustness to expected BPS grid disturbances. The specifications of default values and ranges of allowable settings in IEEE 1547-2018 align well with similar requirements set forth for BPS-connected generating resources.

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*Updated to show ranges based on expected amendment to IEEE 1547-2018*
disturbance level, prorated by the per-unit voltage of the least phase voltage if that voltage is less than nominal.

- During temporary voltage disturbances where voltage falls outside the continuous operation region, DERs “shall be capable to ride-through, shall maintain synchronism with the Area EPS, shall not trip, and shall restore output as specified in Clause 6.4.2.7.” Note that this does not require DER to continue injecting current in this region of the ride-through curves.
  - Within the mandatory operation region, the DER “shall maintain synchronism with the Area EPS, shall continue to exchange current with the Area EPS, and shall neither cease to energize nor trip.”
    - Category II and III DER “shall, by default, not reduce its total apparent current...below 80% of the pre-disturbance value or of the corresponding active current level subject to the available active power, whichever is less...” subject to conditions specified.
  - During temporary voltage disturbances where voltage falls within the permissive operation region, DERs “shall maintain synchronism with the Area EPS or shall not trip, may continue to exchange current with the Area EPS or may cease to energize, and if DER ceases to energize, shall restore output as specified in Clause 6.4.2.7.”
    - Note that permissive operation of DER, as defined in IEEE 1547-2018, is an “operating mode where the DER performs ride-through either in mandatory operation or in momentary cessation”. Therefore, the DER may either provide current injection or may use momentary cessation. Widespread cessation of current injection, with delayed recovery of current to pre-disturbance levels, can have a negative impact to BPS reliability and stability during BPS fault events. Efforts to establish requirements for DER to provide grid-supportive response to BPS disturbances should be sought by all applicable entities.
    - DER performance within this region should be prescribed by the AGIR such that it is clear how DER are being implemented in the field. It is recommended that the appropriate setting (current injection or momentary cessation) be mutually agreed upon by the Area EPS operator, DP, and RC.
    - It is critical that TPs, PCs, and RCs understand how DER are expected to behave during these conditions such that they can be accurately modeled in reliability studies.
  - For Category III DER, a momentary cessation operation region exists for specified low voltage conditions.
- Clause 6.4.2.5 defines performance during consecutive voltage disturbances. It states that “the requirements for continued operation (ride-through), or restore output shall apply to multiple consecutive voltage disturbances within a ride-through operating region, for which the voltage range and corresponding cumulative durations are specified in” Tables 14–16 of IEEE 1547-2018 for Category I, II, and III DER, respectively. These requirements are subject to the provisions that specify conditions in Table 17 of IEEE 1547-2018 for which a DER may trip. Refer to these provisions, specified in Table 17 of IEEE 1547-2018, for more details.

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59 For low-voltage [high-voltage] ride-through, the relevant voltage at any given time shall be the least [greatest] magnitude of the individual applicable phase-to-neutral, phase-to-ground or phase-to-phase voltage relative to the corresponding nominal system voltage.
Clauses 6.5.1 and 6.5.2 – Frequency Mandatory Tripping and Ride-Through

In addition to the voltage mandatory tripping and ride-through requirements, IEEE 1547-2018 also includes frequency-related mandatory tripping and ride-through requirements. These requirements help ensure that DER are able to ride-through frequency disturbance events on the BPS and support BPS stability during abnormal contingency events. The requirements for ride-through only apply while DER frequency and voltage are within the shall-trip limits (as explained in the previous section). New criteria regarding frequency sensing accuracy are also included in IEEE 1547-2018 to better support equipment capability in meeting both mandatory tripping and ride-through requirements.

Clause 6.5.1 - Mandatory Frequency Tripping Requirements

Clause 6.5.1 states the following pertaining to mandatory frequency trip settings:

“When the system frequency is in a range given below, and the fundamental-frequency component of voltage on any phase is greater than 30% of nominal, the DER shall cease to energize the Area EPS and trip within a clearing time as indicated...The underfrequency and overfrequency trip settings shall be specified by the Area EPS operator in coordination with the requirements of the regional reliability coordinator. If the Area EPS operator does not specify any settings, the default settings shall be used.”

Table 1.3 shows the mandatory trip setting default values and ranges of adjustability as defined in Table 18 in IEEE 1547-2018.

Table 1.3: Frequency Trip Settings

<table>
<thead>
<tr>
<th>Default Settings</th>
<th>Ranges of Allowable Settings</th>
</tr>
</thead>
</table>

60 These Category I and II default settings were intended to address prevailing distribution utility concerns to ensure that unintentional islanding (UI) of isolated parts of the distribution grid with DERs is reliably prevented. Latest research by Sandia National Laboratory [24] and EPRI [23], however, falsifies concerns over that smart inverter ride-through performance with enabled grid support functions could extend UI run-on-times beyond 2 s. Independent from smart inverter grid support, run-on-times may exceed 2 s if induction motor loads are present in the isolated feeder.
Similar to the voltage-related trip settings, the frequency-related shall trip settings have been coordinated with the reliability needs of the BPS and are well-aligned with similar requirements for BPS-connected generating resources. AGIRs should seek feedback from RCs to ensure that underfrequency and overfrequency trip settings are coordinated because interconnection frequency response and underfrequency load shedding (UFLS) thresholds vary across RCs and interconnections. IEEE 1547-2018 uses a 0.16 second trip setting as the fastest frequency-related trip threshold, which should further support the ability of DER to support the grid during grid disturbances (see subsequent sections on phase jump and rate-of-change-of frequency (ROCOF)).

### BPS Perspectives and Recommendations

- AGIRs should ensure that underfrequency and overfrequency trip settings are coordinated between the Area EPS operator and the RC to ensure that DER tripping is coordinated with wide-area UFLS operation and interconnection-wide frequency response characteristics.
- The frequency-related shall trip settings of IEEE 1547-2018 are generally set to support BPS reliability, and provide sufficient robustness to expected BPS grid disturbances. The capabilities, and in many cases the default settings, used in IEEE 1547-2018 align well with similar requirements set forth for BPS-connected generating resources. However, the default settings should be reviewed by the AGIR for each specific system.

### Clause 6.5.2 - Frequency Disturbance Ride-Through Requirements

Clause 6.5.2 defines the abnormal frequency ride-through requirements for Category I, II, and III resources in Table 19 of IEEE 1547-2018. Figure H.10 of the standard visualizes these ride-through requirements as well. Appendix B of this guideline includes the ride-through figures from IEEE 1547-2018 for reference. The following notes are useful perspectives to consider when implementing IEEE 1547-2018 based on the Clause 6.5.2 requirements:

- The ride-through requirements, in many cases, are just within the limits of the shall-trip criteria.
- DER will be designed to provide frequency disturbance ride-through capability without exceeding DER capabilities.
- Frequency disturbances of any duration, for which system frequency remains between 58.8 Hz and 61.2 Hz and the per-unit ratio of voltage: frequency is less than or equal to 1.1, shall not cause the DER to trip. The DER shall remain in operation during any such disturbance and shall be able to continue to exchange active power at least as great as its pre-disturbance level of power.
- During temporary frequency disturbances, the DER shall be capable to ride through and maintain synchronism with the Area EPS. DER performance is defined by Tables 20 and 22 of IEEE 1547-2018 based on the DER category selected.
• For temporary low-frequency disturbances within the mandatory operation region, Category II and III DER shall maintain synchronism, have active power output capability equal to pre-disturbance values, and modulate active power per Table 22 of IEEE 1547-2018.

• For temporary high-frequency disturbances, DERs shall maintain synchronism with the Area EPS, shall continue to exchange current with the Area EPS and shall neither cease to energize nor trip, and shall modulate active power to mitigate the overfrequency conditions per Table 22 of IEEE 1547-2018.

• Within the continuous operation region and ride-through operating regions, DERs shall not trip for frequency excursions having a magnitude of rate-of-change-of-frequency (ROCOF) that is less than or equal to the values specified in Table 1.4 (Table 21 of IEEE 1547-2018).

<table>
<thead>
<tr>
<th>Category I</th>
<th>Category II</th>
<th>Category III</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.5 Hz/s</td>
<td>2.0 Hz/s</td>
<td>3.0 Hz/sec</td>
</tr>
</tbody>
</table>

**BPS Perspectives and Recommendations**

• The frequency disturbance ride-through requirements of IEEE 1547-2018 provide significantly improved performance of DER over past versions of IEEE 1547. The ability of DER to ride-through BPS disturbance events, including frequency disturbances, becomes an important component of BPS stability as the penetration of DER continues to increase.

• Categories I, II, and III have the same frequency and voltage phase angle jump disturbance ride-through requirements and help ensure appropriate performance of DER when part of a larger BPS.

• Improvements to ROCOF ride-through, particularly for Category II and III DER, will greatly improve DER ability to ride-through imbalances in generation and load that may occur on the BPS.

**Clause 6.4.2.7 - Restore Output**

Clause 6.4.2.7 defines the restore output with voltage ride-through requirements. These requirements define how DERs shall operate when the applicable voltage returns to within the continuous operation region following it entering the mandatory or permissive operation regions. In all cases, DER shall maintain synchronism with the Area EPS. Performance is then based on whether or not the DER is providing dynamic voltage support:

• If the DER is not providing dynamic voltage support, then it “shall restore output of active current to at least 80% of pre-disturbance active current level within 0.4 s. Active and reactive current oscillations in the post-disturbance period that are positively damped are acceptable.”

• If the DER is providing dynamic voltage support, then it shall:
  • “Continue to provide dynamic voltage support up to 5 s after the applicable voltage surpasses the lower value of the continuous operation region and restore output of active current to at least 80% of pre-disturbance active current level or to the available active current subject to reactive current priority, whichever is less, within 0.4 s.”

61 This Reliability Guideline does not provide a recommendation for the use of dynamic voltage support for DER during fault events. However, fault current contribution and dynamic voltage support from DERs may help support BPS voltage recovery during and following BPS fault events. Coordination with distribution system protection practices will be critical and should be considered by AGIRs during the coordinated implementation process.
“Discontinue providing dynamic voltage support 5 s after the applicable voltage surpasses the lower value of the continuous operation region and resume reactive power functionality for normal conditions as defined in Clause 4.2 for the mode that has been selected.”

Note that areas with any delayed voltage recovery concerns such as those caused by fault induced delayed voltage recovery (FIDVR) may need to consider whether this type of dynamic voltage support being retracted after 5 seconds could impact BPS reliability.

### BPS Perspectives and Recommendations

- In cases where DER do not provide dynamic voltage support and cease injection of current to the Area EPS, active current recovery within 0.4 seconds after voltage returns to within the continuous operating range appears to reasonably support wide-area BPS stability currently. However, in the future this may need to be revisited by TPs and PCs, and should be modeled appropriately in reliability studies.

- TPs and PCs should understand if end-use load dynamics such as motor stalling could result in post-fault voltages remaining low, such that DER are unable to restore output for BPS fault events. This has been observed in events where single-phase induction motor stalling (common in legacy air-conditioning systems), has occurred.

- Continued current injection during abnormal grid conditions helps mitigate potential transient and voltage stability issues on the BPS. As such, DERs providing dynamic voltage support and continuing current injection to the grid during disturbance events provide useful support to the BPS during disturbance events.

### Clause 6.5.2.7 - Frequency-Droop

As more DER displaces generating resources on the BPS, changes to analysis techniques and planning practices are needed to identify issues related to frequency control and balancing generation and demand. Frequency response is an ERS for BPS reliability, and IEEE 1547-2018 requires the technical capability for DERs to provide active power-frequency (i.e., frequency-power or frequency-droop) functionality similar to BPS-connected generating resources. Utilization of this feature with appropriate functional settings should be considered in the near-term to support BPS operation. AGIRs should coordinate with RCs and BAs to ensure appropriate settings are selected to support interconnection-wide power balancing.

The use of active power-frequency controls should be coordinated with any unintentional islanding settings. Concerns about the potential impact on unintentional islanding run-on times should not lead to wider deadband settings for frequency-droop control since that can effectively desensitizes the function’s impact. A proportional response from DERs to high-frequency conditions beyond a deadband can help support BPS frequency control during abnormal frequency conditions, particularly during interconnection-wide system separation events. The tendency of DPs to disable this function for Category I DERs bears a potential risk, which should be considered by each AGIR. Use of Category II for DERs helps minimize this risk.

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63 Note that IEEE 1547-2018 does not allow for this function to be disabled.

64 Wider deadbands may cause delayed response from DERs to frequency disturbances, which will adversely impact BPS frequency control by prolonging the frequency recovery period. A reasonable maximum deadband should be considered in a coordinated manner between the DPs, TPs, and RCs.

65 Reduction of active power above a certain frequency threshold.
Coordination between the DER operator and the responsible transmission entity (e.g., the RC and BA) is essential to ensuring that active power-related settings for the frequency-droop (frequency-power) functions coordinate reliably with BPS practices.

### BPS Perspectives and Recommendations

- As more DER displaces generating resources on the BPS, there are growing concerns about frequency control and balancing generation and demand.
- DER providing frequency response with appropriate settings can provide BPS reliability benefits to balancing and frequency control.
- DER expected to operate at maximum available power can still support BPS frequency for overfrequency conditions.
- Future DER management systems and controls may enable DER to provide upward support for underfrequency conditions when DERs are curtailed. This could provide another ERS to the BPS in the future, if needed. However, this would need to be coordinated with the distribution and transmission system operators to ensure that the frequency-related response is not exacerbating any reliability issues that led to the DER curtailment.

### Clause 6.5.2.7.1 - Frequency-Droop Capability

Clause 6.5.2.7.1 includes requirements for some DER to have the capability to provide active power-frequency control that operates on a droop characteristics. The clause states the following:

> Depending on the DER abnormal operating performance category as described in Clause 4, the DER shall have the capability of mandatory operation with frequency-droop (frequency-power) during low-frequency ride-through and high-frequency ride-through as specified below.

<table>
<thead>
<tr>
<th>Category</th>
<th>Operation for Low-Frequency Conditions</th>
<th>Operation for High-Frequency Conditions</th>
</tr>
</thead>
<tbody>
<tr>
<td>I</td>
<td>Optional (may)</td>
<td>Mandatory (shall)</td>
</tr>
<tr>
<td>II</td>
<td>Mandatory (shall)</td>
<td>Mandatory (shall)</td>
</tr>
<tr>
<td>III</td>
<td>Mandatory (shall)</td>
<td>Mandatory (shall)</td>
</tr>
</tbody>
</table>

The ability of DER to support interconnection-wide frequency control for both underfrequency and overfrequency conditions in the future provides a significant reliability benefit. As more resources are able to provide support to grid frequency perturbations, each individual resource will need to provide less magnitude of response. It is well understood that the majority of DER will operate at maximum available power and be unable to provide upward support for underfrequency conditions. However, having the capability to provide that support enables future grid services should the need arise for DER to provide frequency responsive reserves and operational ability to provide underfrequency response. DER management systems may also unlock the capabilities to provide these services to the BA. By having visibility of DER status and capabilities, an operator or aggregator can provide frequency regulation, demand response or other services.
Clause 6.5.2.7.2 - Frequency-Droop Operation

Clause 6.5.2.7.2 specifies the active power-frequency performance of DER for frequency excursion events. It states the following:

*During temporary frequency disturbances, for which the system frequency is outside the adjustable deadband \( db_{OF} \) and \( db_{UF} \) as specified in Table 24, but still between the trip settings in Table 18, the DER shall adjust its active power output from the pre-disturbance levels, according to the formulas in Table 23.*

Tables 23 and 24 of IEEE 1547-2018 provide the formula for frequency-droop operation for underfrequency and overfrequency conditions and the parameters of these equations for each Category of DER, respectively. Table 1.6 shows the parameter values described in Table 24 of IEEE 1547-2018. Refer to IEEE 1547-2018 for details regarding each parameter value.

### Table 1.6: Parameters of Frequency-Droop Operation (Table 24 of IEEE 1547-2018)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Default Setting</th>
<th>Ranges of Allowable Settings</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Category I</td>
<td>Category II</td>
</tr>
<tr>
<td>( db_{OF}, db_{UF} ) [Hz]</td>
<td>0.036</td>
<td>0.036</td>
</tr>
<tr>
<td>( k_{OF}, k_{UF} )</td>
<td>0.05</td>
<td>0.05</td>
</tr>
<tr>
<td>( T_{response} ) (small signal) [sec]</td>
<td>5</td>
<td>5</td>
</tr>
</tbody>
</table>

- Adjustments shall be permitted in coordination with the Area EPS operator.
- For the single-sided deadband values (\( db_{OF}, db_{UF} \)) ranges, both the lower value and the upper value is a minimum requirement (wider settings shall be allowed). For the frequency droop values (\( k_{OF}, k_{UF} \)) ranges, the lower value is a limiting requirement (the setting shall not be set to lower values) and the upper value is a minimum requirement (the setting may be set to greater values). For the open-loop response time, \( T_{response} \) (small-signal), the upper value is a limiting requirement (the setting shall not be set to greater values) and the lower value is a minimum requirement (the setting may be set to lower values). Any settings different from the default settings in Table 24 shall be approved by the regional reliability coordinator with due consideration of system dynamic oscillatory behavior.
- A Deadband of less than 0.017 Hz shall be permitted.

AGIRs should coordinate with all relevant parties, including the BA and RC, to ensure that appropriate settings and capabilities are enabled for active power-frequency control from DER. AGIRs should ensure that any requirements in place at the BA level could be met by appropriate settings for DER. This applies to current system needs as well as future penetration levels of DER. For example, individual or groups of DERs potentially participating in future frequency responsive reserve requirements or markets may need to meet specific performance capabilities. Further, dispatch capability and visibility of these resources may also be needed to ensure operational ability (i.e., frequency responsive headroom). The ranges of allowable settings enable different types of DERs to be accommodated with slight changes in droop, deadband settings, and response times.
Clause 6.5.2.8 - Inertial Response

Clause 6.5.2.8 states the following related to “inertial response”:

“Inertial response, in which the DER active power is varied in proportion to the rate of change of frequency, is not required but is permitted.”

IEEE 1547-2018 does not include requirements for resources to provide specific performance for the injection of active power with respect to fast-changing frequency (specifically in response to measured rate-of-change-of-frequency (ROCOF)). Note that IEEE 1547-2018 uses the term “inertial response”; however, this term in IEEE 1547-2018 is more effectively named “fast frequency response (FFR)” in this document to avoid confusion. Further, changing active power in response to measured ROCOF is only one means of providing FFR.

While this feature is not required, the ability of DER to respond to rapidly changing frequency does support BPS reliability, particularly for systems with low system inertia that experience high ROCOF conditions. While not necessary, DER with the capability and operational functionality to provide FFR could provide a BPS ERS.

Clause 6.5.2.6 - Voltage Phase Angle Changes Ride-Through

Clause 6.5.2.6 of IEEE 1547-2018, provided below, describes the ride-through performance requirements for single-phase and multi-phase DER for sub-cycle-to-cycle phase angle changes (referred to as “phase jump”) often caused by fault events or line switching operations on the distribution system or BPS:

“Multi-phase DER shall ride through for positive-sequence phase angle changes within a sub-cycle-to-cycle time frame of the applicable voltage of less than or equal to 20 electrical degrees. In addition, multi-phase DER shall remain in operation for change in the phase angle of individual phases less than 60 electrical degrees, provided that the positive sequence angle change does not exceed the stated criterion. Single-phase DER shall remain in operation for phase angle changes within a sub-cycle-to-cycle time frame of the applicable voltage of less than or equal to 60 electrical degrees. Active and reactive current oscillations in the post-disturbance period that are positively damped or momentary cessation of the DER having a maximum duration of 0.5 s shall be acceptable in response to phase angle changes.”

The ability of inverter-based resources connected to the BPS as well as DER to ride through changes in voltage phase angle is critical to reliable operation of the BPS. Multiple grid events have identified that phase jump issues at the distribution system and on the BPS have caused these resources to trip off-line when using legacy settings not aligned
Chapter 1: BPS Perspectives on IEEE 1547-2018 Clauses

with the requirement mentioned above. A BPS line switching event (no fault) in the Western Interconnection tripped a BPS-connected solar PV facility off-line due to the large change in phase angle when the line was re-energized and resumed power flow. In August 2019, a large disturbance in the UK that resulted in operation of UFLS involved about 150 MW of DER tripping on “Vector Shift protection” exceeding 6 degrees.66

BPS Perspectives and Recommendations

- With increased DER penetrations, the ability of DER to ride through large changes in voltage phase angle becomes increasingly important for reliable operation of the BPS. Large changes in voltage phase angle can occur during normally cleared fault events or line switching on the BPS. Widespread tripping of DER during these events could cause adverse impacts to BPS reliability. Therefore, from the BPS perspective, voltage phase angle ride-through capability and performance is strongly recommended for all DER.

Clause 4.10 and Clause 6.6 – Enter Service and Return to Service

From a BPS perspective, there are minimal concerns with connecting individual DER units; however, a significant penetration of DERs can pose challenges when unexpectedly entering service or returning to service following a trip event. When an electric distribution circuit is energized, the end-use loads will instantly resume consuming energy. Thermostatically-controlled loads, including HVAC, water heaters, ovens, etc., lose their diversity and may simultaneously be in the “on” state at re-energization, resulting in an increase in load often referred to as “cold load pickup.” The default Return to Service setting on both legacy IEEE 1547-2003 and newer IEEE 1547-2018 DER is a 300-second delay. So, resulting in an even greater increase in the net load at re-energization that persists until the DER resume pre-disturbance output. Therefore, for areas with high DER penetration, the demand may be significantly higher relative to demand prior to the outage. In addition, substation load tap changers, regulators, and capacitors are all in the position appropriate for DER operation, which may cause challenges upon restoration.

Clause 4.10.2 defines the requirements for DER entering on-line operation (“enter service”). Clause 6.6 references the requirements of Clause 4.10.2 related specifically to return to service after a trip condition. Clause 4.10.2 states:

Following a trip, or when entering service, DER shall not energize the Area EPS until the applicable voltage and system frequency are within the ranges specified in Table and the permit service setting is set to “Enabled”.

Table 1.7 shows the return to service following trip and enter service criteria for Category I, II, and III DER.

<table>
<thead>
<tr>
<th>Enter Service Criteria</th>
<th>Objective</th>
<th>Foundation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Applicable Voltage within Range</td>
<td>Minimum Value</td>
<td>$\geq 0.917 \text{ pu}^a$</td>
</tr>
<tr>
<td></td>
<td>Maximum Value</td>
<td>$\leq 1.05 \text{ pu}$</td>
</tr>
<tr>
<td>Frequency within Range</td>
<td>Minimum Value</td>
<td>$\geq 59.5 \text{ Hz}$</td>
</tr>
<tr>
<td></td>
<td>Maximum Value</td>
<td>$\leq 60.1 \text{ Hz}$</td>
</tr>
</tbody>
</table>

$^a$ Corresponds to Range B of ANSI C84.1, Table 1, column for service voltage of 120–600 V.

Legacy DERs will return to service after steady-state frequency and voltage are restored and after a time delay of up to 5 minutes. At that point, most legacy DER will resume operation nearly simultaneously, causing a significant shift in the net demand on any given feeder with DER penetration. This tends to de-stabilize wide-area black start restoration efforts (and should be coordinated with the BA) where it is critical to maintain balance between load and generation while system inertia is still relatively low. Increasing penetration of DER compliant with IEEE 1547-2018 reduces this potential impact by requiring that DER be capable of ramping up their power output over a prescribed period, with a default of five minutes. Small DER are allowed the option of utilizing a random delay, which in the aggregate of many small DER units, achieves the same behavior as a ramp-up. These settings should help avoid adverse impacts to operation of the BPS during large-scale restoration activities. AGIRs and DPs should review the settings to determine appropriate schemes, which should be coordinated with wide-area blackstart activities.

### BPS Perspectives and Recommendations

- Unexpected or large changes in DER output may adversely impact BA and RC restoration activities following wide-area disturbances. BAs and RCs need to understand expected load pickup behavior following outage conditions, including the response of DERs.
- AGIRs should ensure that return to service and enter service settings are coordinated among DPs, BAs, and RCs. Appropriate voltage and frequency limits, in additional to return to service time, should be coordinated with all entities.

### Clause 8.1 - Unintentional Islanding

For an unintentional island in which the DER energizes a portion of the Area EPS through the PCC, Clause 8.1.1 requires the DER to “detect the island, cease to energize the Area EPS, and trip within 2 seconds of the formation of an island. The same clause clarifies the important requirement that “[f]alse detection of an unintentional island that does not actually exist shall not justify noncompliance with ride-through requirements as specified in Clause 6” of the standard. The latest draft of IEEE P1547.1 requires that DER anti-islanding performance be demonstrated in type-testing with the widest voltage and frequency tripping set points and with grid support functionality (voltage regulation and frequency droop) enabled. However, limited testing on actual systems with many parallel inverters (and end-use loads) has been performed in the field; therefore, AGIRs should understand that continuous monitoring and feedback may be needed in this area.

Despite this clear and strong language on unintentional islanding detection requirements in IEEE 1547-2018 and in the forthcoming IEEE 1547.1 testing and verification standard, the Category I and II default settings were intended to address prevailing distribution utility concerns to ensure that unintentional islanding (UI) of isolated parts of the distribution grid with DERs is reliably prevented. However, latest research by Sandia [24],[31] and EPRI [23] indicates that smart inverter ride-through performance with enabled grid support functions does not extend UI run-on-times beyond 2 seconds.\(^{67,68}\) Ongoing industry research is needed to determine appropriate islanding detection sensitivities in cases of high penetration of DERs.

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\(^{67}\) Testing by Sandia National Lab showed that DERs conforming to IEEE 1547 with grid support functions enabled showed roughly a 3x factor for UI run-on-times; however, none exceeded 2 seconds. Further research by Sandia found potential failures to detect islands when varying islanding detection methods were applied by different DERs as well as when synchronous machines were present.

\(^{68}\) Independent from grid support functions, run-on-times may exceed two seconds when dissimilarities from the standard test circuits are present in the distribution feeder. Clause 8.1.2 allows the clearing time for UI prevention to be extended from two seconds to as much as five seconds upon mutual agreement between the Area EPS operator and the DER operator. However, many utilities do not consider this a suitable practice.
Clause 8.2 – Intentional Islanding
Intentional islanding refers to a planned electrical island capable of being energized by one or more Local EPSs, which have one or more DERs and load (e.g., a planned island that independently energizes a local or wider-area network during a BPS outage). Clause 8.2 and its various sub-clauses describe intentional islanding, which may be either an island of the DER and the Local EPS or may include parts of the Area EPS; however, such an island is intentionally disconnected from other parts of the distribution system and the larger BPS. The sub-clauses cover the creation of intentional islands, the transition to and from these islanded conditions, and how DER should operate when connected in this manner (which may include modifications to settings when they are connected to the Area EPS which is then connected to the BPS). Clause 8.2.8 describes categorizations of DER based on their performance in these islands: uncategorized, intentional island-capable, black start-capable, and isochronous-capable.

BPS Perspectives and Recommendations

- The settings and performance of DER related to intentional islanding is outside the scope of consideration by SPIDERWG and recommendations provided by NERC.

Clause 10 – Interoperability, Information Exchange, and Protocols
Clause 10 provides a standardization of the local DER communications interface and protocols, but does not require any specific external communication channel to be utilized. A standard local DER communication interface makes it easier, if allowed, for DPs or other third-parties to perform monitoring and management or control (changing settings) of DER. Such interoperability may be a critical need for managing systems with high penetration levels of DER in the future. This communication may also be a future requirement by BAs in order to have adequate visibility and control of DER that are participating in either wholesale energy or ancillary service markets.

Transmission and distribution entities, as well as regulatory entities (e.g. AGIRs), will need to provide appropriate guidance on policies for accommodating these needs. Specific policies, protocols, and mediums of communication should be established by these entities in a coordinated manner. Relevant topics include, but are not limited to, the following:

- The expected timeline for when a communication and control system may be needed
- The technology and required performance level of the communication system to support specific use cases
- The communication networks and architecture standards needed
- The types and size of DER necessary to be integrated into this standardized communication interface
- The specific owners and operators of each level and type of communication integration system (e.g., the local distribution entity or other third party)
- Clear regulatory policies that ensure consumer protections for utilization of control functions, with different requirement standards for when control is required

Figure 1.8 illustrates one of many communications interface models that could be utilized, and that should be considered by each AGIR as needed [30]. The industry is currently working towards specifying the messages that may be exchanged between BPS operators, DPs, and DER owners [29].

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69 A comprehensive DER integration strategy likely would involve a staged approach.
Figure 1.8: Example of Possible Architecture for DER Management and Control
[Source: EPRI]

BPS Perspectives and Recommendations

- A standardized local DER communication interface would allow authorized entities (e.g., DPs or others) to perform monitoring and management or control (e.g., changing settings) of DER, which may be a critical need for managing systems with high penetration levels of DER in the future.

- DERs should be installed with communications capabilities defined in IEEE 1547-2018 as the visibility and control of DER operation may become necessary for BAs and other entities as DER penetration increases.

- AGIRs should consider whether specific policies, protocols, and mediums of communication should be established for DER. This should consider potential future penetration levels of DER.
Appendix A: References


Appendix B: Ride-Through Requirements in IEEE 1547-2018

Figure B.1: Category I Abnormal Voltage Ride-Through Requirement
[Source: © 2018 IEEE]

Figure B.2: Category II Abnormal Voltage Ride-Through Requirement
[Source: © 2018 IEEE]
Figure B.3: Category III Abnormal Voltage Ride-Through Requirement, as amended in 2020
[Source: © 2018 IEEE]

Figure B.4: Category I, II, and III Abnormal Frequency Ride-Through Requirement
[Source: © 2018 IEEE]
Appendix C: Definitions used in IEEE 1547-2018

The following definitions are used in IEEE 1547-2018, and are provided here as a reference.

**Area electric power system (Area EPS):** An EPS that serves Local EPSs.

NOTE—Typically, an Area EPS has primary access to public rights-of-way, priority crossing of property boundaries, etc., and is subject to regulatory oversight.

**Area electric power system operator (Area EPS operator):** The entity responsible for designing, building, operating, and maintaining the Area EPS.

**Authority governing interconnection requirements (AGIR):** A cognizant and responsible entity that defines, codifies, communicates, administers, and enforces the policies and procedures for allowing electrical interconnection of DER to the Area EPS. This may be a regulatory agency, public utility commission, municipality, cooperative board of directors, etc. The degree of AGIR involvement will vary in scope of application and level of enforcement across jurisdictional boundaries. This authority may be delegated by the cognizant and responsible entity to the Area EPS operator or bulk power system operator.

NOTE—Decisions made by an authority governing interconnection requirements should consider various stakeholder interests, including but not limited to Load Customers, Area EPS operators, DER operators, and bulk power system operator.

**Bulk power system (BPS):** Any electric generation resources, transmission lines, interconnections with neighboring systems, and associated equipment.

**Cease to energize:** Cessation of active power delivery under steady-state and transient conditions and limitation of reactive power exchange.

NOTE 1—This may lead to momentary cessation or trip.
NOTE 2—This does not necessarily imply, nor exclude disconnection, isolation, or a trip.
NOTE 3—Limited reactive power exchange may continue as specified, e.g., through filter banks.
NOTE 4—Energy storage systems are allowed to continue charging but are allowed to cease from actively charging when the maximum state of charge (maximum stored energy) has been achieved.
NOTE 5—Refer to 4.5 for additional details.

**Continuous operation:** Exchange of current between the DER and an EPS within prescribed behavior while connected to the Area EPS and while the applicable voltage and the system frequency is within specified parameters.

**Distributed energy resource (DER):** A source of electric power that is not directly connected to a bulk power system. DER includes both generators and energy storage technologies capable of exporting active power to an EPS. An interconnection system or a supplemental DER device that is necessary for compliance with this standard is part of a DER.

**Energize:** Active power outflow of the DER to an EPS under any conditions (e.g., steady state and transient).

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70 Note that this definition of bulk power system differs from the definition in the NERC Glossary of Terms. However, it captures the general essence of the NERC definition of BPS. This document uses the NERC definition of BPS throughout.
**Mandatory operation:** Required continuance of active current and reactive current exchange of DER with Area EPS as prescribed, notwithstanding disturbances of the Area EPS voltage or frequency having magnitude and duration severity within defined limits.

**Momentary cessation:** Temporarily cease to energize an EPS, while connected to the Area EPS, in response to a disturbance of the applicable voltages or the system frequency, with the capability of immediate Restore Output of operation when the applicable voltages and the system frequency return to within defined ranges.

**Permissive operation:** Operating mode where the DER performs ride-through either in mandatory operation or in momentary cessation, in response to a disturbance of the applicable voltages or the system frequency.

**Point of common coupling (PCC):** The point of connection between the Area EPS and the Local EPS.

- NOTE 1—See Figure 2.
- NOTE 2—Equivalent, in most cases, to “service point” as specified in the National Electrical Code® and the National Electrical Safety Code®.

**Point of distributed energy resource connection (PoC):** The point where a DER unit is electrically connected in a Local EPS and meets the requirements of this standard exclusive of any load present in the respective part of the Local EPS.

- NOTE 1—See Figure 2.
- NOTE 2—For (a) DER unit(s) that are not self-sufficient to meet the requirements without (a) supplemental DER device(s), the point of DER connection is the point where the requirements of this standard are met by DER (a) device(s) in conjunction with (a) supplemental DER device(s) exclusive of any load present in the respective part of the Local EPS.

**Restore output:** Return operation of the DER to the state prior to the abnormal excursion of voltage or frequency that resulted in a ride-through operation of the DER.

**Return to service:** Enter service following recovery from a trip.

**Ride-through:** Ability to withstand voltage or frequency disturbances inside defined limits and to continue operating as specified.

**Trip:** Inhibition of immediate return to service, which may involve disconnection.

- NOTE—Trip executes or is subsequent to cessation of energization.
Contributors

NERC gratefully acknowledges the invaluable contributions and assistance of the following industry experts in the preparation of this guideline. NERC would like to acknowledge the technical contributions of EPRI for the leadership in developing this guideline.71 NERC also would like to acknowledge all the contributions of the NERC SPIDERWG and IEEE P1547.2 Working Group.

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71 EPRI and its members are working on a project titled *Navigating DER Interconnection Standards and Practices* to develop guidance on adoption of IEEE 1547-2018. For more information, see https://www.epri.com/#/pages/product/3002012048/.
Reliability Guideline
DER Data Collection for Modeling in Transmission Planning Studies
March 2020
Table of Contents

Preface ........................................................................................................................................................................... iii
Preamble ........................................................................................................................................................................ iv
Executive Summary ........................................................................................................................................................... v
Introduction ................................................................................................................................................................... vi
  Background ................................................................................................................................................................. vi
  Recommended DER Modeling Framework ............................................................................................................... vii
  Types of Reliability Studies ....................................................................................................................................... viii
  Case Assumptions ....................................................................................................................................................... ix
Timeline and Projections of DER Interconnections ...................................................................................................... x
Chapter 1: MOD-032-1 Data Collection Process ............................................................................................................. 1
  MOD-032-1 Data Collection and DER .......................................................................................................................... 2
Chapter 2: Steady-State Data Collection Requirements ................................................................................................ 3
  DER Modeling Needs for TPs and PCs ......................................................................................................................... 3
  Mapping TP and PC Modeling Needs to DER Data Collection Requests ................................................................... 4
Chapter 3: Dynamics Data Collection Requirements ................................................................................................ 6
  DER Modeling Needs for TPs and PCs ......................................................................................................................... 6
  Mapping TP and PC Modeling Needs to DER Data Collection Requests ................................................................... 7
Chapter 4: Short-Circuit Data Collection Requirements ............................................................................................... 11
  Applications of Short-Circuit Studies ......................................................................................................................... 11
  Potential Future Conditions for DER Data and Short-Circuit Studies ...................................................................... 11
  Differentiating Inverter-Based DERs ......................................................................................................................... 13
  Considering Short-Circuit Response from DERs and Loads ....................................................................................... 13
  Aggregate DER Data for Short-Circuit Studies ........................................................................................................... 14
  Example where DER Modeling Needed for Short-Circuit Studies ........................................................................... 14
Chapter 5: GMD Data Collection Requirements ........................................................................................................... 15
Chapter 6: EMT Data Collection Requirements ........................................................................................................... 16
  DER Modeling Needs for TPs and PCs ......................................................................................................................... 16
  Mapping TP and PC Modeling Needs to DER Data Collection Requests ................................................................... 17
Appendix A: References ................................................................................................................................................ 18
Appendix B: Data Collection for DER Energy Storage .................................................................................................. 19
Appendix C: DER Data Provision Considerations ....................................................................................................... 22
Contributors ................................................................................................................................................................... 26
**Preface**

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is divided into six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.

<table>
<thead>
<tr>
<th>MRO</th>
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Preamble

It is in the public interest for NERC to develop guidelines that are useful for maintaining or enhancing the reliability of the Bulk Electric System (BES). The NERC technical committees (the Operating Committee (OC), the Planning Committee (PC), and the Critical Infrastructure Protection Committee (CIPC)) are authorized per their charters by the NERC Board of Trustees (Board) to develop reliability (OC and PC) and security guidelines (CIPC). These guidelines establish a voluntary code of practice on a particular topic for consideration and use by BES users, owners, and operators. These guidelines are coordinated by the technical committees and include the collective experience, expertise, and judgment of the industry. The objective of this reliability guideline is to distribute key practices and information on specific issues critical to maintaining the highest levels of BES reliability. Reliability guidelines are not to be used to provide binding norms or create parameters by which compliance to standards is monitored or enforced. While the incorporation of guideline practices are strictly voluntary, reviewing, revising, or developing a program using these practices is highly encouraged to promote and achieve the highest levels of reliability for the BES.

NERC, as the FERC certified ERO, is responsible for the reliability of the BES and has a suite of tools to accomplish this responsibility, including, but not limited to, lessons learned, reliability and security guidelines, assessments and reports, the Event Analysis Program, the Compliance Monitoring and Enforcement Program, and mandatory reliability standards. Each entity as registered in the NERC compliance registry is responsible and accountable for maintaining reliability and compliance with the mandatory standards to maintain the reliability of their portions of the BES. Entities should review this guideline in detail in conjunction with the periodic review of their internal processes and procedures and make any needed changes to their procedures based on their system design, configuration, and business practices.

2 http://www.nerc.com/comm/CIPC/Related%20Files%20DL/CIPC%20Charter%2020131111with%20BOT%20Approval%20Footer.pdf
Executive Summary

Modeling the BPS for performing BPS reliability studies hinges on the availability of data and information needed to represent the various elements of the grid. While many individual BPS elements are modeled explicitly, some components are represented in aggregate. These include representation of end-use loads as well as a growing focus on the representation of aggregate amounts of distributed energy resources (DERs). As the penetration of DERs continues to grow, representing DERs in planning assessments becomes increasingly important. Steady-state powerflow, dynamics, short-circuit, electromagnetic transient (EMT), and other types of planning studies may need information and data that enable Transmission Planners (TPs) and Planning Coordinators (PCs) to develop models of aggregate amounts of DERs for planning purposes.

TPs and PCs establish modeling data requirements and reporting procedures per the requirements of NERC Reliability Standard MOD-032-1.5 These requirements should include specifications for collecting aggregate DER data for the purposes of modeling, particularly as DER penetration levels continue to increase. Clear and consistent requirements developed by the TPs and PCs will help facilitate the transfer of information between the Distribution Providers (DPs) and any other external parties such as state regulatory entities or other entities performing DER forecasting to the TP and PC for modeling purposes. The modeling data requirements established by TPs and PCs may differentiate utility-scale DER (U-DER) and retail-scale DER (R-DER) based on their size, impact, or location on the distribution system. U-DER may require detailed information regarding the facility; whereas smaller-scale R-DER data will typically represent aggregate amounts of DERs. TPs and PCs should establish clear requirements and any applicable thresholds regarding DER modeling practices; however, aggregated amounts of DERs should be accounted and reported to the TP and PC for modeling purposes.

The goal of this Reliability Guideline is to provide clear recommendations and guidance for establishing effective modeling data requirements on collecting aggregate DER data for the purposes of reliability studies. TPs and PCs should review their requirements to ensure they encompass the considerations presented in this guideline. DPs are encouraged to review the recommendations and reference materials to better understand the types of modeling data needed by the TP and PC, and to help facilitate this data and information transfer. In many cases, the aggregate data needed for the purposes of modeling may not require detailed information from individual DERs; rather, aggregate data related to location, type of DERs, vintage of IEEE 1547, interconnection timeline and projections, and other key data points can help develop aggregate DER models. In instances of larger U-DERs, more detailed modeling information may be needed if those DERs can have an impact on BPS performance. In either case, the DP, TP, and PC should coordinate on the best approaches for gathering aggregate DER data for modeling purposes.

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3 Such as BPS transformers, generators, circuits, and other elements.
4 Typically loads are aggregated to each distribution transformer. Therefore, all loads connected to that distribution transformer are represented as one load in the steady-state base case, and then an aggregate representation of the dynamic performance of those loads are developed using engineering judgment combined with available data.
6 U-DER and R-DER are terms used for modeling aggregate amounts of DER. This Reliability Guideline furthers the flexible framework established in previous NERC Reliability Guidelines. See: https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf.
Introduction

The ability to develop accurate models for BPS reliability studies hinges on the availability of data and information needed to represent the various elements of the grid. While many individual BPS elements are modeled explicitly such as transformers, large BPS generators, transmission lines, etc., some components of the grid are represented in aggregate for the purposes of BPS studies. Such models include the representation of end-use loads as well as a growing focus on the representation of aggregate amounts of DERs. TPs and PCs are establishing modeling data requirements for DER data for the purposes of transmission planning assessments, and reasonable representation of DER in the models used to execute these studies will be increasingly important. Distribution Providers (DPs) likely account for aggregate DER connected to their systems, with varying degrees of detail and information available.

The primary objective of this Reliability Guideline is to provide recommended practices for PCs and TPs to work with DPs to facilitate the transfer of data needed to represent aggregate DER in BPS reliability studies. The detailed guidance provided in this guideline follows the required data transfer established in NERC Reliability Standard MOD-032-1, which is described below in more detail. Data collection requirements and reporting procedures established by each TP and PC are expected to vary slightly based on the types of studies being performed as well as how those studies are performed. However, there are commonalities in the type of data needed to model DER and in how that data can be collected.

Background

The NERC Reliability Guideline Modeling DER in Dynamic Load Models, published December 2016, established a foundation for classifying DER as either utility-scale DER (U-DER) or retail-scale DER (R-DER) for the purpose of modeling. That guideline also provided a flexible framework for modeling U-DER and R-DER in the steady-state powerflow base cases as well as options for modeling DER in the dynamic models. This included options for representing DER using a stand-alone DER dynamic model or integrating DER as part of the composite load model. The NERC Reliability Guideline Distributed Energy Resource Modeling, published September 2017, provided further guidance on establishing reasonable parameter values for the DER dynamic models. That guideline reviewed the available dynamic models and recommended default parameter values that could be used as a starting point for modeling DER. The NERC Reliability Guideline Parameterization of the DER_A Model recommended use of the DER_A dynamic model to represent either U-DER or R-DER in dynamic simulations. This model was in the process of being developed during the publication of the previous two guidelines. Therefore, that guideline demonstrated the benchmarking and testing of the DER_A model and also provided recommended default parameter values for the DER_A model for different scenarios of DER installation in various systems. Again, the recommendations presented in that guideline are intended to be a starting point for planning engineers to further determine representative DER dynamic model parameter values.

The NERC Distributed Energy Resources Task Force (DERTF) also published a technical report on Distributed Energy Resources: Connection Modeling and Reliability Considerations in December 2016 and a technical brief on Data Collection Recommendations for Distributed Energy Resources in March 2018. Both of these reports provided industry with a high-level overview of the information that may need to be collected and shared among entities for...
the purposes of modeling and studying DER impacts as well as monitoring DERs in real-time. Further, they emphasized that netting of DERs with load should be avoided since it can mask the impacts that either may have on BPS reliability, particularly for dynamic simulations.

The goal of this Reliability Guideline is to build upon all these past efforts and specifically focus on gathering the data and modeling information needed to effectively execute transmission planning modeling and study activities.

**Recommended DER Modeling Framework**

The recommendations regarding DER data collection for the purposes of modeling and transmission planning studies use the recommended DER modeling framework proposed in previous NERC Reliability Guidelines (see Figure I.1).

For the purposes of modeling, the framework characterizes DERs as either utility-scale DER (U-DER) or retail-scale (R-DER). These definitions are intended to be adapted to specific TP and PC planning practices and specific DER installations, as needed. For reference, from the previous DER modeling recommendations, these definitions are provided here as a reference:

- **U-DER:** DERs directly connected to, or closely connected to, the distribution bus or connected to the distribution bus through a dedicated, non-load serving feeder. These resources are typically three-phase interconnections and can range in capacity (e.g., 0.5 to 20 MW).

- **R-DER:** DERs that offset customer load, including residential, commercial, and industrial customers. Typically, the residential units are single-phase while the commercial and industrial units can be single- or three-phase facilities.

Both U-DERs and R-DERs can be differentiated and modeled in powerflow base cases and dynamic simulations. TPs and PCs have successfully adapted these general definitions for their system, and often refer to U-DER and R-DER for the purposes of modeling aggregate DERs. Aggregate amounts of all DERs should be accounted for in either U-DER or R-DER models in the base case, and TPs and PCs may establish requirements for modeling either individual large U-DER as well as aggregate amounts of the remaining DER as R-DER. The aggregate impact of DERs, such as the sudden loss of a large amount of DERs, and has been observed to have an impact on BPS reliability.

**Types of Reliability Studies**

Data of BPS elements as well as other necessary aspects of the interconnected BPS are used in a wide array of reliability studies performed by TPs and PCs. In particular, studies considered by SPIDERWG include the following:

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15 Some entities have chosen to model large U-DER that are connected to load-serving feeders as U-DER explicitly in the base case as well. This has been demonstrated as an effective means of representing U-DER as well, and is a reasonable adaptation of the definition above.
16 This also applies to community DERs that do not serve any load directly but are interconnected directly to a single-phase or three-phase distribution load serving feeder.
18 Such as aggregate demand (steady-state) and the dynamic nature of end-use loads (dynamics).
• **Steady-State Studies:** Steady-state reliability studies include both powerflow analysis of future operating conditions as well as steady-state contingency analysis. In addition, steady-state stability studies typically include voltage stability (P-V and Q-V analysis) as well as small signal eigenvalue analysis. These studies all require information regarding the end-use load as well as possible DER penetration to accurately model the behavior of these resources in future normal and abnormal operating conditions.

• **Dynamic Studies:** Dynamic studies typically refer to phasor-based, time-domain simulations of the interconnected BPS. These studies include performing contingencies and identifying any potential instabilities, uncontrolled separation, or cascading events that may occur due to dynamic behavior of the BPS and all the elements connected to it. The data used in these simulations also represents the aggregate effects of end-use loads as well as aggregate DERs. DERs, particularly in dynamic simulations, can have a relatively significant impact on BPS performance for voltage stability due to re-dispatched dynamic reactive devices on the BPS, rotor angle stability due to changes in BPS-connected generation dispatch, and frequency stability due to changes in rate of change of frequency and frequency response performance.

• **Short Circuit Studies:** Short circuit studies are used for a wide range of analyses such as assessing breaker duty and setting protective relays. As DERs continue to offset BPS-connected generation, particularly during higher DER output levels, short circuit conditions may need to be assessed more regularly or close attention may be needed in certain areas of low short circuit strength. This is particularly a concern for systems with high penetrations of DERs as well as BPS-connected inverter-based resources. At a high level, as described in Chapter 4, as DER penetrations continue to increase, some DER data associated with short circuit performance may be needed in the future.

• **Geomagnetic Disturbance (GMD) Studies:** GMD studies are performed for applicable facilities per NERC TPL-007-3, which analyzes the risk to BPS reliability that could be caused by quasi-dc geomagnetically-induced currents (GICs) resulting in transformer hot-spot heating or damage, loss of reactive power sources, increased reactive power demand, and misoperation of system elements due to GMD events. TPL-007-3 GIC vulnerability assessments typically do not model the distribution system for various reasons, mainly because the transmission-distribution (T-D) transformers include a delta-wye transformation, with GICs not propagating through delta windings and distribution circuits being relatively short in length (with high impedance). Therefore, negative effects of GMD at this level are minimal and not likely to impact the distribution system. Based on this finding, DER modeling for the purposes of GMD vulnerability assessments per NERC TPL-007-3 is likely not needed at this time.

• **Electromagnetic Transient (EMT) Studies:** Given the higher fidelity models, EMT analysis for DER interconnections can be useful in finding weak grid control instabilities, voltage control coordination issues, confirming ride through capability, and benchmarking positive sequence RMS models. Items such as ride
through and voltage response can be better represented in EMT studies than traditional positive sequence RMS studies. This is important when large groups of DER (relative to the size of the system) are interconnected. While EMT studies are not necessary for all DER interconnections it can be a useful tool when large amounts of aggregate DER are connecting to areas where system strength is of concern.

Case Assumptions

Similar to end-use load models, the assumptions used for modeling DERs will dictate how the resource(s) should be represented in planning base cases. NERC TPL-001-4 requires that planning assessments use steady-state, stability, and short-circuit studies to determine whether the BES meets performance requirements for system peak and off-peak conditions. TPs and PCs need to determine and specify these conditions to ensure clarity in data submittals from DPs. For example, solar PV DER is highly dependent on time of day, which is closely linked to the assumptions used in creating the base cases. In some areas, system peak loading may occur during late afternoon when active power output from solar PV is minimal (as illustrated in Figure I.2 and discussed below).

PCs and TPs should clearly identify the assumptions used in planning cases as part of their data requirements so that DPs can effectively provide this information for the purposes of modeling aggregate DERs in planning base cases. Note that these studies are generally used to determine whether the BPS is robust enough to handle expected or impending operating conditions and credible contingencies based on the study results obtained. The following assumptions should be clearly defined for each base case in the TP and PC data requirements:

- **Year:** Each base case represents a specific year being studied. TPs forecast expected demand levels, and should also forecast the aggregate amount of DERs for each year being modeled. This data is based on local or regional DER growth trends, and can come from multiple data sources.\(^\text{27}\)

- **Season:** Each base case typically has a specified season (e.g., summer, spring, winter) or type of season (e.g., shoulder season), which is already defined in the planning process.

- **Time of Day:** Each TP and PC should identify the critical times of day that should be studied, which is often dependent on the time when gross load peaks (or hits its minimum) and when DER peaks (or hits its minimum). The time of day used in each base case should be clearly defined by each TP and PC to aid in the data collection from DPs related to DER.

- **Load (Peak versus Off-Peak):** The NERC TPL-001 standard uses terms such as “System peak Load” and “System Off-Peak Load”; however, it is not clear if these terms refer to gross or net load (demand) conditions. Therefore, it is recommended that TPs and PCs clearly articulate which load is being referred to in the case creation process. As the penetration of DERs continues to grow, it is likely that both peak and off-peak gross load and net load conditions should both be studied for potential reliability issues. This is particularly applicable to systems where the gross load and net load peak and off-peak conditions are significantly different.

- **DER Dispatch Assumptions:** The TP and PC likely have established assumptions around how the DER will be dispatched in the planning base cases. While this may not directly affect the information flow from the DP to the TP and PC, these assumptions may help the DP in gathering the necessary data and information needed. These dispatch assumptions may include both active power output levels and reactive power capability. Additional planning base cases should reflect expected stressed system conditions that depend on the geospatial and temporal patterns of demand and DERs, and their impact on BPS-connected generation dispatch (most notably, BPS-connected synchronous generation). These conditions might include heavy transmission flows that have a very different pattern than during peak-load conditions.

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\(^\text{27}\) Such as state incentive policy forecasts or other relevant regional DER forecasting tools.
To illustrate this concept, consider the development of the interconnection-wide "System Peak" base case. Refer to Figure I.2 for a visualization of this example. Let us assume that this is a summer peak case, so the season has been defined. Then it is determined that the gross load peaks around 6 PM local time, which defines the time of day. Based on this time, the DER output assumptions are established — DER output is assumed to be roughly 40-50% of its maximum capability at this time. Since the majority of DER were installed prior to 2015, they are likely compliant with IEEE Std. 1547-2003 and therefore provide little voltage support (unity power factor). This defines both the active and reactive power output assumptions to be used in the base case. This concept applies to off-peak loading conditions as well as system peaking in winter as well.

Using the established case creation assumptions and DER modeling requirements specified by the TP and PC (described in the following sub-section), the DP can provide the necessary DER data needed to represent the aggregate DER in planning cases.

**Timeline and Projections of DER Interconnections**

The TP and PC are focused on developing planning base cases with reasonable assumptions of future BPS scenarios, including BPS generation, demand, and aggregate DERs. Accounting for the currently installed penetration of DERs helps the TP and PC understand what the existing system contains regarding DERs. This information, in most cases, should be provided by the DP to support data sharing across the transmission-distribution interface. Further, the TP and PC should develop forecasts for DER growth into future years. This information may or may not be available to the DP; however, if the DP or state-level agency or regulatory body is performing DER forecasting for the purposes of distribution planning, this information may be available. In many cases, regional forecasts may be available from other data sources that could be useful for the DP, TP, and PC. If external sources (e.g., DER forecasts through state-level forecasts) are used by the DP, the DP should share that information with the TP and PC so they can incorporate those forecasts into their planning practices. Therefore, development of planning base cases uses a combination of data for existing DERs and projections of DERs.

Visualization of DER penetration, both existing and forecasted values, can be useful to the TP for the purposes of modeling DER in steady-state powerflow base cases as well as dynamic simulations. Chapters 2 and 3 describe why understanding and estimating the vintage of DERs installed can be of significant value for the purposes of DER modeling.

**Example of Applying DER Interconnection Timelines**

Consider Figure I.3, which shows an example system with actual installed DER capacity from early 2010 to the end of 2019, as illustrated by the solid blue curve. The TP and PC are in the process of developing a 5-year out 2025 base case, and therefore have pulled in forecasted DER growth (dotted blue curve) from either the DP or an external source (e.g., state-level agency or regulator body) that projects DER out to the end of 2025.

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Assume all DERs connected to this example system are inverter-based and therefore comply with the various versions of IEEE 1547. For example, up to November 2016, due to interconnection requirements at the time, assume DERs were installed with settings compliant with IEEE 1547-2003. After November 2016 up to an assumed July 2021, assume that DERs were installed with settings compliant with IEEE 1547a-2014. Finally, after July 2021, assume that DERs will be installed with settings compliant with IEEE 1547-2018 once interconnection requirements are updated and compliant equipment becomes available. The red numbers show the amount of aggregate DER capacity that meet each standard implementation. It is clear that a small amount of resources are compliant with IEEE 1547-2003 while the remaining majority are mixed between IEEE 1547a-2014 and IEEE 1547-2018. The revised IEEE 1547-2018 includes much more robust ride-through performance and the capability for active power-frequency control on overfrequency conditions. In this example, no resources are required to maintain headroom to respond to underfrequency conditions. Interconnection requirements will presumably be updated in July 2021 to required local DER voltage control (volt-var capability) as well.

Based on this information alone, the TP and PC can make reasonable assumptions regarding the following modeling considerations:

- Overall capacity of DERs connected to the system
- The percentage of DERs responding to overfrequency disturbances
- The assumption that no DERs will respond to underfrequency disturbances
- The assumed DER ride-through capability, and frequency and voltage trip settings
- The assumed DER ride-through performance in terms of active and reactive current injection
- The percentage of DERs controlling voltage (steady-state)

The ability of TPs and PCs to understand when DERs were installed will greatly improve their ability to use engineering judgment to assume modeling parameters. This is particularly important for modeling aggregate amounts of R-DERs where minimal information is available.

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29 https://standards.ieee.org/standard/1547a-2014.html
Chapter 1: MOD-032-1 Data Collection Process

The purpose of NERC Reliability Standard MOD-032-1 is to “establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.” MOD-032-1 serves as the foundation for the development of the interconnection-wide planning base cases that are used as a starting point by TPs and PCs to perform their reliability assessment per the NERC Reliability Standard TPL-001. The requirements and overall flow of data is shown in Figure 1.1, specifically related to DER modeling information. The process is described briefly with the following steps:

- Requirement R1 of MOD-032-1 requires that each PC and each of its TPs jointly develop data requirements and reporting procedures for steady-state, dynamics, and short circuit modeling data collection.
  - These requirements should include the data listed in Attachment 1, as well as any additional data deemed necessary for the purposes of modeling.
  - The specifications should address the data format, the level of detail, assumptions needed for the various types of planning cases or scenarios, a data submittal timeline, and posting the data requirements and reporting procedures.

- Requirement R2 of MOD-032-1 requires each of the applicable entities to provide the modeling data to the TPs and PCs according to the requirements specified.

- Requirement R3 requires each of the applicable entities to provide either updated data or an explanation with a technical basis for maintaining the current data if a written notification is provided to them by the PC or TP with technical concerns regarding the data submitted.

- Requirement R4 requires each PC to make the models for its footprint available to the Electric Reliability Organization (ERO) or its designee to support the creation of the interconnection-wide base cases.

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31 This generally includes any model-related formats, possible software versioning, or other relevant data submittal formatting issues. Practices for collecting data differ from each TP and PC to integrate with their planning practices.

32 Including each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider. Note that at the time of writing this guideline, a Standard Authorization Request was submitted by the NERC Distributed Energy Resources Task Force (DERTF) to replace LSE with DP since the registration of LSE was removed. SPIDERWG also submitted a SAR further emphasizing that the DP is the appropriate entity to support collection of DER data. Therefore, DP is used as the applicable entity throughout this document.

33 In each interconnection of the NERC footprint, a “MOD-032 Designee” has been designated to create the interconnection-wide base cases. Each Designee has a signed agreement with NERC to develop base cases of sufficient data quality, fidelity, and timeliness for industry to perform its planning assessments.
MOD-032-1 Data Collection and DER

Attachment 1 of MOD-032-1 “indicates information that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon... A [PC] may specify additional information that includes specific information required for each item in the table below”, as illustrated in Figure 1.2.

Currently, the table in Attachment 1 does not provide a line item for aggregate DER data. Rather, the table includes a statement in each of the columns that states “other information requested by the [PC] or [TP] necessary for modeling purposes” should be collected. This item can be used by the TP and the PC as technical justification for collecting aggregate DER data necessary for modeling purposes.

Regardless of the elements explicitly defined in MOD-032-1 Attachment 1, each TP and PC should jointly develop data requirements and reporting procedures for the purpose of developing the interconnection-wide base cases used for transmission planning assessments. These requirements are often very detailed and specific to each PC and TP planning practices, tools, and study techniques. Therefore, TPs and PCs should ensure that their data reporting requirements for Requirement R1 of MOD-032-1 explicitly describe the requirements for aggregate DER data in a manner that is clear and consistent with their modeling practices. Chapter 2 provides a foundation and starting point for establishing the specific information that should be gathered, in coordination with the DP, for modeling purposes.

Key Takeaway:
TPs and PCs should ensure that their data reporting requirements required under Requirement R1 of MOD-032-1 include specific requirements for aggregate DER data from the appropriate entities who have access to this data.

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34 Refer to items #9 and #10 in the steady-state and dynamics columns in NERC MOD-032-1, respectively.
35 The NERC Planning Committee, on behalf of the NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG), has also endorsed and submitted a Standard Authorization Request (SAR) to the NERC Standards Committee to include DER data collection as a specific line item in a revision to MOD-032, specifically in the table in Attachment 1.
Chapter 2: Steady-State Data Collection Requirements

This chapter describes the recommended data reporting requirements for collecting sufficient data to model aggregate DER in interconnection-wide powerflow base cases. Each PC, in coordination with their TPs, should consider integrating these recommendations into their requirements per MOD-032-1 Requirement R1.

DER Modeling Needs for TPs and PCs

Modeling data requirements for steady-state aggregate DER data should be explicitly defined in the modeling data requirements established by each PC and TP per MOD-032-1. This section describes the recommended data necessary for representing the aggregate DER in steady-state powerflow base cases.

TPs and PCs will generally model the gross load and aggregate DER at specific BPS buses or distribution buses at the low-side of the T-D transformers (depending on modeling practices). To accomplish the latter, TPs and PCs require T-D transformer modeling data for explicit representation in the powerflow model, and can then assign the gross load and aggregate DERs connected to the low-side bus accordingly. The TP and PC should collect aggregate DER data for each T-D transformer so this can be modeled correctly. Therefore, it is recommended for DPs to have some accounting of DER at either of these levels, in coordination with the TP and PC data reporting needs.

The DER models in the steady-state power flow base case, whether represented as a generator record (U-DER) or as a component of the load record (R-DER), have specific data points that must be accurately populated in order to represent the aggregate DER. These data points, on a bus-level or T-D transformer level, include the following:

- Location, both electrical and geographic
- Type of DER (or aggregate type)\(^{37}\)
- Historical DER output profiles\(^{38}\)
- Status
- Maximum DER active power capacity (P\(_{\text{max}}\))\(^{39}\)
- Minimum DER active power capacity (P\(_{\text{min}}\))
- Maximum DER reactive power capability (Q\(_{\text{max}}\), producing vars)
- Minimum DER reactive power capability (Q\(_{\text{min}}\), consuming vars)
- Reactive power-voltage control operating mode\(^{40}\)

\(^{36}\) Modeling on a T-D transformer basis is the most common approach for DER modeling, where the T-D transformer is explicitly modeled and the aggregate load and aggregate DERs from the connected distribution feeders are represented. However, some TPs and PCs may have different modeling practices (e.g., by feeder-level basis), and therefore their requirements for data collection of DER may be slightly different.

\(^{37}\) This may be defined as part of the generator name, generator ID, or load record ID, and may be useful as the penetration of DER continues to increase and different types of DER may need to be tracked.

\(^{38}\) If meter-level data is available, profiles of DER output help TPs and PCs understand how the DER should be dispatched in the powerflow base case. This is essential for developing reasonable base cases that represent expected operating conditions of the BPS, including the operation of aggregate DERs.

\(^{39}\) The preferred approach for renewable, inverter-based DERs is for the DP to provide the total aggregate DER capacity and the TP and PC can set the active power output (P\(_\text{gen}\)) of the DER in the powerflow to an appropriate level based on the assumptions specified for each case. For large synchronous DERs, similar data collection requirements for steady-state modeling data can be used as would be used for BPS-connected resources.

\(^{40}\) TPs and PCs should consider local DER interconnection requirements regarding power factor and reactive power-voltage control operating modes, where applicable. These modes may include operation at a set power factor (e.g., unity power factor or some of static power factor level) or operation in automatic voltage control. TPs and PCs can configure the powerflow models by adjusting Q\(_\text{max}\), Q\(_\text{min}\), and the mode of operation to appropriately model aggregate DERs.
If the unit is represented as a U-DER and modeled with a generator record, then a generator step up (GSU) transformer should be modeled. This model may represent an explicit U-DER facility or can be used to represent multiple U-DER facilities. The TP and PC may need specific information pertaining to the following to accurately represent this element:

- Transformer impedances
- Equivalent feeder or generator tie line impedance (for large U-DER facilities), if applicable
- Load tap changer status and settings

The majority of newly interconnecting DER across North America are either rooftop solar PV (R-DER) or utility-scale solar PV (U-DER) facilities. The TP and PC may request that the DP provide a reasonable estimate or differentiation between U-DER and R-DER resources, to reasonably represent these resources in the base case. This may simply be a percentage value of the estimate of R-DER versus U-DER, and possibly the number and size of U-DER resources. While individual accounting of R-DER is very unlikely and inefficient, typically the accounting of U-DER is much more straightforward since these resources are typically relatively large (e.g., 0.5 to 20 MW).

On the other hand, DER other than solar PV should be noted by the DP since these resources (e.g., battery energy storage, wind, small gas engines, combined heat and power facilities) may have different operational characteristics. For example, these resources may operate at different hours of the day, which would change the dispatch pattern when studying different hourly system conditions. DPs should have the capability to account for these different types of DER to aid in the development of the base case models for the TP and PC.

**Mapping TP and PC Modeling Needs to DER Data Collection Requests**

The information described above defines the necessary information that will be needed by TPs and PCs to model aggregate DER as either U-DERs or R-DE Rs. However, this information will likely not need to be provided or collected by the TP and PC for each individual DER. Rather, these entities will need a reasonable understanding of the aggregate DER information. This section provides a mapping between the TP and PC needs and the information that should be requested from DPs by TPs and PC as part of MOD-032. Table 2.1 shows how the DER modeling needs are mapped to data requests.

**Example of Mapping DER Information for Steady-State Powerflow Modeling**

To apply the concepts described in Table 2.1, consider an example where aggregate DER data is being provided by the DP (possibly in coordination with external parties such as a state regulatory body or other entity performing state-level DER forecasts) to the TP and PC. Following the structure of Table 2.1, the TP and PC would receive useful data for steady-state powerflow modeling:

- 50 MW total aggregate DER, allocated to T-D transformer (per TP and PC modeling requirements)
- 35 MW is considered U-DER and 15 MW is considered R-DER (based on TP and PC modeling practices)
- Of the U-DER, 20 MW is solar PV and 15 MW is BESS (i.e., ± 15 MW)
- Of the R-DER, all 15 MW is solar PV
- About 75% of these resources are likely IEEE 1547-2003 vintage and the remaining are IEEE 1547a-2014
- All DER operates at unity power factor

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41 In some cases, for generator tie line modeling, the MVA rating and length may be needed by the TP and PC.
42 These values are used as a guideline in the DER modeling framework; however, they can be adapted based on specific modeling needs.
**Table 2.1: Steady-State Powerflow Modeling Data Collection**

<table>
<thead>
<tr>
<th>Aggregate DER Modeling Information Needed</th>
<th>Information Necessary for Suitable Modeling of Aggregate DERs</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Location</strong></td>
<td>The DER interconnection location will need to be assigned to a specific T-D transformer or associated BPS or distribution bus based on the TP and PC modeling practices. Geographic location should also be given so that proper DER (e.g., solar) profiles and estimated impedance can be applied.</td>
</tr>
<tr>
<td><strong>Type of DER (or aggregate type)</strong></td>
<td>Specify the percentage of DERs considered R-DER and U-DER. Provide an aggregate breakdown (percentage) of the types of DERs per T-D transformer. Preferably, this is specified as a percentage of aggregate DERs that are solar PV, synchronous generation, energy storage, hybrid power plants, and any other types of DERs.</td>
</tr>
<tr>
<td><strong>Historical DER output profiles</strong></td>
<td>For each type of aggregate DER (e.g., solar PV, combined heat and power, energy storage, etc.), specify a general historical DER output profile occurring during the studied conditions. What output are these resources dispatched to during peak and off-peak conditions? The TP and PC should define what peak and off-peak conditions are (e.g., season, time of day, etc.).</td>
</tr>
<tr>
<td><strong>Status</strong></td>
<td>Based on the DER output profile provided, TPs and PCs will know whether to set the aggregate DER model to in-service or out-of-service based on assumed normal operating conditions for the case.</td>
</tr>
<tr>
<td><strong>Maximum DER active power capacity (Pmax)</strong></td>
<td>Maximum active power capacity of aggregate DERs should be provided to the TP and PC. This, again, should be aggregated to a T-D transformer basis, categorized by DER type, depending on the TP and PC requirements.</td>
</tr>
<tr>
<td><strong>Minimum DER active power capacity (Pmin)</strong></td>
<td>Minimum active power capacity of aggregate DERs should also be provided, similar to maximum capacity. Systems with energy storage may have a Pmin value for aggregate DER modeling less than since the storage resources may be able to charge when generation DERs are at 0 MW output.</td>
</tr>
<tr>
<td><strong>Reactive power-voltage control operating mode</strong></td>
<td>Are the DERs controlling local voltage? Or are they set to operate at a fixed power factor? If some are operating in one mode while others are operating in a different mode, estimate the percentage in each mode using engineering judgment based on time of interconnection.</td>
</tr>
<tr>
<td><strong>Maximum DER reactive power capability (Qmax and Qmin)</strong></td>
<td>If DERs are controlling voltage, they have a reactive capability that should be modeled appropriately. If they are operating at a fixed power factor, what value? Qmax and Qmin can be configured for each aggregate DER representation in the model accordingly. In some cases for U-DER, a capability curve may be needed for accurate reactive capability at different active power levels (at least Qmax/Qmin at Pmax and Pmin values).</td>
</tr>
</tbody>
</table>

---

43 The granularity of information submitted to the TP and PC by the DP should be defined in the data reporting requirements established by the TP and PC. This is most commonly on a T-D transformer basis.


45 Hybrid plants combine generation and energy storage, and have different operational characteristics than either individual type of DER.

46 Qmax refers to producing vars and Qmin refers to consuming vars.

47 If this information is not know, the vintage of IEEE 1547-2018 standard could be useful to apply engineering judgment to develop a conservative capability curve.
Chapter 3: Dynamics Data Collection Requirements

This chapter describes the recommended data reporting requirements for collecting sufficient data to model aggregate DER in interconnection-wide dynamics cases. Each PC, in coordination with their TPs, should consider integrating these recommendations into their requirements per MOD-032-1 Requirement R1.

DER Modeling Needs for TPs and PCs

Dynamics modeling data requirements for aggregate DER should be explicitly defined in the modeling data requirements established by each PC and TP per MOD-032-1. This section describes the recommended data necessary for representing the aggregate DER in dynamic simulations performed by TPs and PCs to ensure BPS reliability. Refer to the existing NERC Reliability Guidelines regarding DER modeling for more information about recommended dynamic modeling approaches for DERs. While synchronous DERs exist across North America, inverter-based DERs (e.g., solar PV and battery energy storage) are rapidly being interconnected to the system in many areas. Therefore, this section will use the DER_A dynamic model as an example for describing necessary information for the purposes of developing DER dynamic models.

The DER_A dynamic model is the recommended model for representing inverter-based DERs (i.e., wind, solar PV, BESS). The DER_A model is appropriate for representing R-DER modeled as part of a component of the load model (e.g., using the composite load model) and U-DER and R-DER modeled as a standalone generator record in the powerflow case. The TP and PC will need to specify what their modeling practices are regarding U-DER and R-DER:

- How are U-DER and R-DER differentiated in the planning base cases?
- Is a size threshold used to differentiate resources? Or is this based on location along the distribution feeder(s)?
- Are the details of DER data different in any way between U-DER and R-DER?
- Are there specific interconnection requirements applicable to either U-DER, R-DER, or both?
- Are U-DER expected to have higher performance requirements for participating in energy markets?
- Are U-DER resources combining generation and energy storage (i.e., hybrid plants), and are these technologies ac-coupled or dc-coupled, and what are the operational characteristics of the facility (i.e., how is charging and discharging of the energy storage portion modifying total plant output)?
- Are there specific distribution-level tripping schemes or return to service requirements that would apply during the dynamics timeframe that differ from applicable IEEE 1547-2018 requirements?

The DER_A dynamic model consists of many different parameter values that are used to parameterize different control philosophies and performance capabilities for aggregate or individual inverter-based DERs; however, most of the parameter values remain fixed when representing different DER vintages. Therefore, it is important to focus primarily on the control modes of operation and parameter values that change based on what types and vintages of DERs are connected to the distribution system. The following sub-section will describe how gathering this data can be a fairly straightforward task, and provide adequate information for the TP and PC to be able to use engineering judgment to model aggregate DERs in their footprint.

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48 DERs that are synchronously connected to the grid exist across North America; in some areas, these are the predominant type of DER. The DER modeling guidelines mentioned above can be referenced and adapted for gathering DER data for the purposes of modeling these resources.

49 For example, representing DERs compliant with different versions of IEEE 1547 (e.g., -2003, -2018, etc.).
Mapping TP and PC Modeling Needs to DER Data Collection Requests

As mentioned, the complexity and number of parameter values of the DER_A dynamic model should not prohibit or preclude entities from developing relatively straightforward information sharing to gather the needed data for TPs and PCs to be able to model these resources. Table 3.1 shows how parameterization of the DER_A dynamic model can be mapped to questions that should be asked by the TP and PC and to information that should be provided by the DP or other external entity to help facilitate DER model development. Note that the table describes IEEE 1547 and its various versions; however, the concepts would also apply to other local or regional rules such as California Rule 21 or Hawai’i Rule 14H. Values listed in red are those that are likely subject to change across different vintages of the IEEE 1547 standard, and would likely need to be modified to account for systems with DERS with varying vintages of IEEE 1547.50 This is intended as an example51 to help illustrate how the TP and PC could map questions related to DER information for the purposes of developing an aggregate DER dynamic model.

### Table 3.1: Data Collection for Parameterizing the DER_A Dynamic Model

<table>
<thead>
<tr>
<th>Param</th>
<th>Default Parameters for IEEE 1547-2018 Systems (Category II)</th>
<th>Information Necessary for Suitable Modeling of Aggregate DERs</th>
</tr>
</thead>
<tbody>
<tr>
<td>trv</td>
<td>0.02</td>
<td>Parameter values do not generally change between vintages of IEEE 1547. No information needed from DP for the purposes of modeling, assuming that these default parameters are appropriate. In cases where the TP or PC has determined that these default parameters are not appropriate, the TP or PC may request additional information of the DP for this purpose.</td>
</tr>
<tr>
<td>dbd1</td>
<td>-99</td>
<td></td>
</tr>
<tr>
<td>dbd2</td>
<td>99</td>
<td></td>
</tr>
<tr>
<td>kqv</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>vref0</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>tp</td>
<td>0.02</td>
<td></td>
</tr>
<tr>
<td>tiq</td>
<td>0.02</td>
<td></td>
</tr>
<tr>
<td>ddn</td>
<td>20</td>
<td>Are DERs required to have frequency response capability enabled and operational for overfrequency conditions? As in, do DERs respond to overfrequency conditions by automatically reducing active power output based on this type of active power-frequency control system? If so, what are the required droop characteristics for these resources (e.g., 5% droop would equal a ddn gain of 20)? What is the estimated fraction of resources installed on your system that are required to have this capability (based on interconnection date and requirements)?</td>
</tr>
<tr>
<td>dup</td>
<td>0</td>
<td>Are DERs required to have frequency response capability enabled and operational for underfrequency conditions? As in, if there is available energy, do DERs respond to underfrequency conditions by automatically increasing active power output based on this type of active power-frequency control system? Are there any requirements for DERs to have headroom to provide underfrequency response? If so, what are the required droop characteristics for these resources? What is the estimated fraction of resources installed on your system that are required to have this capability (based on interconnection date and requirements)?</td>
</tr>
<tr>
<td>fbd1</td>
<td>-0.0006</td>
<td>If frequency response capability is enabled and operational, the deadband should be set to match any interconnection requirements governing this capability and performance. Consider the different types of interconnection requirements and what the correct assumption would be for this parameter, where applicable.</td>
</tr>
<tr>
<td>fbd2</td>
<td>0.0006</td>
<td>If frequency response capability is enabled and operational, the deadband should be set to match any interconnection requirements governing this capability and performance. Consider the different types of interconnection requirements and what the correct assumption would be for this parameter, where applicable.</td>
</tr>
</tbody>
</table>


51 Note that the order of parameters and exact names of parameters may be slightly different across software platforms. Refer to a specific software vendor model library for exact parameter names and order of parameters. However, the concepts contained within this guideline can be applied regardless.
Table 3.1: Data Collection for Parameterizing the DER_A Dynamic Model

<table>
<thead>
<tr>
<th>Param</th>
<th>Default Parameters for IEEE 1547-2018 Systems (Category II)</th>
<th>Information Necessary for Suitable Modeling of Aggregate DERs</th>
</tr>
</thead>
<tbody>
<tr>
<td>femax</td>
<td>99</td>
<td>Values vary based on what vintage of IEEE 1547 the DERs are; therefore, a timeline of interconnection capacity estimating the amount and timing of DER interconnection will support modeling.</td>
</tr>
<tr>
<td>femin</td>
<td>-99</td>
<td>Values vary based on what vintage of IEEE 1547 the DERs are; therefore, a timeline of interconnection capacity estimating the amount and timing of DER interconnection will support modeling.</td>
</tr>
<tr>
<td>pmax</td>
<td>1</td>
<td>Parameter values do not generally change between vintages of IEEE 1547. No information needed from DP for the purposes of modeling, assuming that these default parameters are appropriate. In cases where the TP or PC has determined that these default parameters are not appropriate, the TP or PC may request additional information of the DP for this purpose.</td>
</tr>
<tr>
<td>pmin</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>dpmax</td>
<td>99</td>
<td></td>
</tr>
<tr>
<td>dpmín</td>
<td>-99</td>
<td></td>
</tr>
<tr>
<td>tpard(^2)</td>
<td>5</td>
<td></td>
</tr>
<tr>
<td>lmax</td>
<td>1.2</td>
<td>Parameter values do not generally change between vintages of IEEE 1547. No information needed from DP for the purposes of modeling, assuming that these default parameters are appropriate. In cases where the TP or PC has determined that these default parameters are not appropriate, the TP or PC may request additional information of the DP for this purpose.</td>
</tr>
<tr>
<td>vi0</td>
<td>0.44</td>
<td></td>
</tr>
<tr>
<td>vi1</td>
<td>0.49</td>
<td></td>
</tr>
<tr>
<td>vh0</td>
<td>1.2</td>
<td></td>
</tr>
<tr>
<td>vh1</td>
<td>1.15</td>
<td></td>
</tr>
<tr>
<td>tvl0</td>
<td>0.16</td>
<td></td>
</tr>
<tr>
<td>tvl1</td>
<td>0.16</td>
<td></td>
</tr>
<tr>
<td>tvh0</td>
<td>0.16</td>
<td></td>
</tr>
<tr>
<td>tvh1</td>
<td>0.16</td>
<td></td>
</tr>
<tr>
<td>Vfrac</td>
<td>1.0</td>
<td>Values vary based on what vintage of IEEE 1547 the DERs are; therefore, a timeline of interconnection capacity estimating the amount and timing of DER interconnection will support modeling.</td>
</tr>
<tr>
<td>fltrp</td>
<td>56.5</td>
<td>Values vary based on what vintage of IEEE 1547 the DERs are; therefore, a timeline of interconnection capacity estimating the amount and timing of DER interconnection will support modeling.</td>
</tr>
<tr>
<td>fhtrp</td>
<td>62.0</td>
<td>Values vary based on what vintage of IEEE 1547 the DERs are; therefore, a timeline of interconnection capacity estimating the amount and timing of DER interconnection will support modeling.</td>
</tr>
<tr>
<td>tfl</td>
<td>0.16</td>
<td>Parameter values do not generally change between vintages of IEEE 1547. No information needed from DP for the purposes of modeling, assuming that these default parameters are appropriate. In cases where the TP or PC has determined that these default parameters are not appropriate, the TP or PC may request additional information of the DP for this purpose.</td>
</tr>
<tr>
<td>tff</td>
<td>0.16</td>
<td></td>
</tr>
<tr>
<td>tg</td>
<td>0.02</td>
<td></td>
</tr>
<tr>
<td>rppwr</td>
<td>2.0</td>
<td>Values vary based on what vintage of IEEE 1547 the DERs are; therefore, a timeline of interconnection capacity estimating the amount and timing of DER interconnection will support modeling.</td>
</tr>
</tbody>
</table>

\(^2\) The active power-frequency response from DERs, if utilized in studies, should be tuned to achieve and ensure a closed-loop stable control. This parameter may need to be adapted based on this tuning.
Table 3.1: Data Collection for Parameterizing the DER_A Dynamic Model

<table>
<thead>
<tr>
<th>Param</th>
<th>Default Parameters for IEEE 1547-2018 Systems (Category II)</th>
<th>Information Necessary for Suitable Modeling of Aggregate DERs</th>
</tr>
</thead>
<tbody>
<tr>
<td>tv</td>
<td>0.02 Parameter values do not generally change between vintages of IEEE 1547. No information needed from DP for the purposes of modeling, assuming that these default parameters are appropriate. In cases where the TP or PC has determined that these default parameters are not appropriate, the TP or PC may request additional information of the DP for this purpose.</td>
<td></td>
</tr>
<tr>
<td>Kpg</td>
<td>0.1 Values vary based on what vintage of IEEE 1547 the DERs are; therefore, a timeline of interconnection capacity estimating the amount and timing of DER interconnection will support modeling.</td>
<td></td>
</tr>
<tr>
<td>Kig</td>
<td>10.0 Values vary based on what vintage of IEEE 1547 the DERs are; therefore, a timeline of interconnection capacity estimating the amount and timing of DER interconnection will support modeling.</td>
<td></td>
</tr>
<tr>
<td>xe</td>
<td>0.25 Parameter values do not generally change between vintages of IEEE 1547. No information needed from DP for the purposes of modeling, assuming that these default parameters are appropriate. In cases where the TP or PC has determined that these default parameters are not appropriate, the TP or PC may request additional information of the DP for this purpose.</td>
<td></td>
</tr>
<tr>
<td>vyth</td>
<td>0.3 TP and PC engineering judgment can be used to set this parameter value. May be subject to change across vintages of IEEE 1547 for the purposes of modeling.</td>
<td></td>
</tr>
<tr>
<td>iqh1</td>
<td>1.0 Parameter values do not generally change between vintages of IEEE 1547. No information needed from DP for the purposes of modeling, assuming that these default parameters are appropriate. In cases where the TP or PC has determined that these default parameters are not appropriate, the TP or PC may request additional information of the DP for this purpose.</td>
<td></td>
</tr>
<tr>
<td>iqI1</td>
<td>-1.0</td>
<td></td>
</tr>
<tr>
<td>pfflag</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>fflag</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>pflag</td>
<td>Q priority Values vary based on what vintage of IEEE 1547 the DERs are; therefore, a timeline of interconnection capacity estimating the amount and timing of DER interconnection will support modeling.</td>
<td></td>
</tr>
<tr>
<td>typeflag</td>
<td>1 What penetration of energy storage resources are connected to the distribution system? What percentage of DERs are energy storage? Are these larger utility-scale energy storage DERs, or more distributed (e.g., residential) energy storage DERs? Any values or estimates as the interconnection of energy storage DERs will help determine whether to and how to separate out energy storage DERs in the models.</td>
<td></td>
</tr>
</tbody>
</table>

Table 3.1 highlights the concept that interconnection timeline is critical for the purposes of creating dynamic models of aggregate DER because the capabilities and performance of DERs is dominated by the interconnection requirements set forth on those DERs. TPs and PCs may have additional data points that provide useful information for capturing more information relevant to developing reasonable DER models, and may have other data points needed for modeling larger U-DER installations (depending on whether additional requirements or data are needed). For DER model parameter values that vary with the vintage of IEEE 1547, a timeline of interconnection capacity can be shared to estimate the amount and time in which resources were interconnected.

To recap the relevant information needed for aggregate DER dynamic modeling, the following data points should be considered by TPs, PCs, DPs, and other external entities in the development of requirements and when providing this information for modeling purposes:53

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53 The TP and PC will need to consider these points when developing aggregate DER dynamic models, and therefore will need information from the DP and any other external entities that may be able to help provide information in these areas.
• What is the vintage of IEEE 1547 that is applicable to the DERs? If it is a mixed collection of vintages, based on the interconnection date, engineering judgment should be used by the DP, TP, and PC to assign percentages to different vintages, as applicable.

• Do the installed or projected future installations of DERs have the capability to provide frequency response in the upward or downward direction? If so, are there any relevant requirements or markets in which DERs may be dispatched below maximum available active power?

• Are DERs providing dynamic voltages support or any fault current contribution, or are they entering momentary cessation?

• What are the expected trip settings (both voltage and frequency) associated with the vintages of IEEE 1547 or other local or regional requirements that may dictate the performance of DERs?

• Are DERs installed on feeders that are part of UFLS programs? If so, more detailed information regarding the expected penetration of DERs on these feeders may be needed. As stated previously, hybrid U-DER facilities likely need specific, more detailed modeling considerations by the TP and PC, and therefore should be differentiated accordingly.
Chapter 4: Short-Circuit Data Collection Requirements

This chapter briefly describes considerations that should be made for gathering aggregate DER data for the purposes of short-circuit modeling and studies at the BPS level. Note that aggregate DER data collection for the purposes of distribution-level short-circuit studies is not considered.

Applications of Short-Circuit Studies

In general, short-circuit studies are used by transmission entities in two key ways: breaker duty assessment, and setting protective relays.

- **Breaker Duty Assessments:** In breaker duty assessments, the assumption of “all resources on-line” is used as a worst case assumption for ensuring that BPS breakers will always be rated sufficiently to clear BPS fault events. This assumption has been used extensively in the past and will likely continue to be used in the future for these types of studies. In any system, the “significance” of aggregate DER fault current will need to be considered by the engineer performing the studies. In areas where breakers are very close to their duty rating, then aggregate DER contributions may be warranted (particularly of localized issues).

- **Setting Protective Relays:** Protective relay setting analyses study “all lines in-service” conditions as well as credible outage conditions that can affect the fault current characteristics of the local network. Alternate contingency events are selected and studied to ensure correct relay operation for a wide range of system configurations. In this case, the focus is not on equipment ratings; rather, it is on secure protection system operation. As the penetration of BPS-connected inverter-based resources as well as DERs continues to increase, their impact on BPS fault current impacts will become more “significant” and therefore will need to be considered. This will likely be on a case-by-case basis in the near-term; however, this type of aggregate DER modeling data will likely be needed on a more regular basis in the future. Not fully modeling potential impacts to BPS fault current can have an adverse impact on setting protective relays.

Potential Future Conditions for DER Data and Short-Circuit Studies

As the BPS continues to experience an increase in the penetration of BPS-connected inverter-based resources as well as DERs, short-circuit modeling and study practices may need to evolve. In some cases, aggregate DER data (along with possibly end-use load data) may become increasingly important for BPS short-circuit studies. In particular, each TP and PC should consider Table 4.1 which lays out potential future conditions where aggregate DER data may be needed for short-circuit modeling. Table 4.1 is intended as a guide to help describe the considerations as they relate to specific system needs and therefore the need for aggregate DER short-circuit modeling data.

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54 “Significance” is used loosely and generally in this discussion, but becomes increasingly important under high penetration DER conditions.
This would be caused both by BPS-connected inverter-based resources as well as the DERs. This will need to be analyzed closely, and coordinated between distribution and transmission planning and protection engineers.

Decreasing fault current magnitude and uncertain phase angle relationship between voltages and currents from inverter-based resources. Further, some BPS-grid by the inverter during low or high voltage conditions outside the continuous operating range.

The power electronics interface of inverter-based resources limits fault current contribution from these resources. Further, some BPS-connected solar PV resources may employ momentary cessation which is an operating state for inverters where no current is injected into the grid by the inverter during low or high voltage conditions outside the continuous operating range.

Consideration: Some areas are experiencing this condition today (e.g., CAISO, ISO-NE). The growth of DERs in conjunction with increasing BPS-connected inverter-based resources is leading to a high overall inverter-based system. Increased BPS-connected inverter-based resources is still affecting fault characteristics on the BPS. Legacy DERs are likely not providing fault current due to the use of momentary cessation for large disturbances, and there likely has been a lack of interconnection requirements to specify behavior for DERs during fault events. Inverter-based DERs providing fault current, where applicable, may have an impact on localized breaker duty studies, and may need to be considered for setting protective relays. On a broader scale, synchronous generators dominate BPS fault current; the impedance between DERs and the BPS fault is so large that DER fault current contribution is relatively low. Therefore, TPs and PCs will need to explore this on a case-by-case basis but should ensure the ability to collect aggregate DER data.

Consideration: Few, if any, areas of the North American BPS experience situations like this today; however, this scenario may be more likely in the future (even within the planning horizon). Lack of on-line synchronous generators causes low fault current magnitudes. DER interconnection requirements for new-vintage DERs may allow for momentary cessation as a default setting (i.e., SJ47-2018). Existing and future installations of DERs may not provide fault current unless momentary cessation is prohibited by local requirements. Where DERs are providing fault current, inverter-based DERs can only provide a limited magnitude of current and their contribution will be primarily for nearby local faults; the impedance between the DERs and the BPS fault location cause their contribution to be low. BPS protective relaying could experience issues under these types of scenarios either due to very low fault current levels or unknown/unstudied fault current behavior (e.g., phase relationship). Solutions may be needed to maintain acceptable levels of fault current (e.g., synchronous condensers). Some synchronous generation will likely remain on-line for the foreseeable future (i.e., hydro generators), which can provide a suitable amount of fault current in those areas. However, as the primary source of generation (and possibly fault current) in this scenario, aggregate DERs may need to be modeled in short-circuit studies. Aggregate representation of the DERs is likely suitable, so long as any significant differences in fault current contribution is differentiated. TPs and PCs will need to assess the potentiality of this scenario and determine whether they should proactively collect aggregate DER data for short-circuit modeling.

Table 4.1: Potential Future Conditions for DER Data Collection for Short-Circuit Studies

<table>
<thead>
<tr>
<th>#</th>
<th>Potential Future Conditions and Considerations</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Condition: BPS-connected synchronous generators dominate, and DERs are not prevalent</td>
</tr>
<tr>
<td></td>
<td>Consideration: This may be the status quo for some entities. BPS-connected synchronous generators provide significant fault current, and aggregate DERs and end-use loads are typically not modeled because the majority of fault current comes from synchronous machines.</td>
</tr>
<tr>
<td>2</td>
<td>Condition: Resource mix consists of both BPS-connected inverter-based and synchronous generators, and DERs are not prevalent</td>
</tr>
<tr>
<td></td>
<td>Consideration: This is likely the status quo for many entities, with growing penetrations of BPS-connected wind and solar PV but fairly low penetrations of DERs. BPS fault currents are decreasing due to the BPS-connected inverter-based resources. Aggregate DERs and end-use loads are generally not modeled in short-circuit studies because the majority of fault current still comes from the BPS (mainly synchronous generators).</td>
</tr>
<tr>
<td>3</td>
<td>Condition: BPS resource mix consists of both synchronous and inverter-based resources, and DERs are becoming increasingly prevalent</td>
</tr>
<tr>
<td></td>
<td>Consideration: Some areas are experiencing this condition today (e.g., CAISO, ISO-NE). The growth of DERs in conjunction with increasing BPS-connected inverter-based resources is leading to a high overall inverter-based system. Increased BPS-connected inverter-based resources is still affecting fault characteristics on the BPS. Legacy DERs are likely not providing fault current due to the use of momentary cessation for large disturbances, and there likely has been a lack of interconnection requirements to specify behavior for DERs during fault events. Inverter-based DERs providing fault current, where applicable, may have an impact on localized breaker duty studies, and may need to be considered for setting protective relays. On a broader scale, synchronous generators dominate BPS fault current; the impedance between DERs and the BPS fault is so large that DER fault current contribution is relatively low. Therefore, TPs and PCs will need to explore this on a case-by-case basis but should ensure the ability to collect aggregate DER data.</td>
</tr>
<tr>
<td>4</td>
<td>Condition: DERs can provide the majority of energy to end-use customers during certain instances; these conditions are likely coupled with increasing BPS-connected inverter-based resources and limited on-line synchronous generators</td>
</tr>
<tr>
<td></td>
<td>Consideration: Few, if any, areas of the North American BPS experience situations like this today; however, this scenario may be more likely in the future (even within the planning horizon). Lack of on-line synchronous generators causes low fault current magnitudes. DER interconnection requirements for new-vintage DERs may allow for momentary cessation as a default setting (i.e., SJ47-2018). Existing and future installations of DERs may not provide fault current unless momentary cessation is prohibited by local requirements. Where DERs are providing fault current, inverter-based DERs can only provide a limited magnitude of current and their contribution will be primarily for nearby local faults; the impedance between the DERs and the BPS fault location cause their contribution to be low. BPS protective relaying could experience issues under these types of scenarios either due to very low fault current levels or unknown/unstudied fault current behavior (e.g., phase relationship). Solutions may be needed to maintain acceptable levels of fault current (e.g., synchronous condensers). Some synchronous generation will likely remain on-line for the foreseeable future (i.e., hydro generators), which can provide a suitable amount of fault current in those areas. However, as the primary source of generation (and possibly fault current) in this scenario, aggregate DERs may need to be modeled in short-circuit studies. Aggregate representation of the DERs is likely suitable, so long as any significant differences in fault current contribution is differentiated. TPs and PCs will need to assess the potentiality of this scenario and determine whether they should proactively collect aggregate DER data for short-circuit modeling.</td>
</tr>
</tbody>
</table>

55 The power electronics interface of inverter-based resources limits fault current contribution from these resources. Further, some BPS-connected solar PV resources may employ momentary cessation which is an operating state for inverters where no current is injected into the grid by the inverter during low or high voltage conditions outside the continuous operating range.

56 Decreasing fault current magnitude and uncertain phase angle relationship between voltages and currents from inverter-based resources.

57 This will need to be analyzed closely, and coordinated between distribution and transmission planning and protection engineers.

58 This would be caused both by BPS-connected inverter-based resources as well as the DERs.
Differentiating Inverter-Based DERs

It may be prudent for TPs and PCs to consider separating requirements for inverter-based and synchronous DERs due to their relatively different impacts on BPS fault characteristics. Synchronous DERs such as low head hydro, run of river hydro, and combined heat and power plants likely should be modeled in short-circuit studies since they can be a significant source of fault current in that local area. However, these are relatively rare, with the majority of newly interconnecting DERs being inverter-based (e.g., solar PV and BESSs). Inverter-based DERs may only provide a relatively small fault current (i.e., on the order of 1.1 pu maximum), if any. IEEE 1547-2018 allows for the use of momentary cessation during low voltages such as during fault events, and therefore fault current from DERs may very well be minimal or zero in the future. This type of information should be considered by the TP and PC performing short-circuit studies.

Example Impact of Aggregate DERs on BPS Fault Characteristic

Whether or not a specific DER (i.e., U-DER) or aggregate amounts of DERs (i.e., R-DER as well as U-DER) have a significant impact on the BPS will need to be determined (likely through study) by the TP and PC performing such studies. During SPIDERWG discussions, one utility provided a rough rule-of-thumb for DER impacts to be the following:

- At 500kV, 1-2A/MW
- At 230kV, 4-5A/MW
- At 115kV, 7-8 A/MW
- At 66 kV, 10-15 A/MW

These values assume a 3-phase fault is applied at the transmission or sub-transmission system bus where the DERs (and end-use loads) are directly being served out of, and roughly account for typical impedance between the DERs and the transmission-distribution (T-D) interface. These numbers will vary by system configuration, but they demonstrate a relative impact as DER penetrations continue to increase across large portions of the BPS.

Considering Short-Circuit Response from DERs and Loads

Inverter-based DERs providing fault current have limitations due to the power electronics interface of the inverter. These devices are typically limited to around 1.1 pu current. On the other hand, synchronous motor loads may consume substantially more current during the fault, offsetting any contribution from DERs along the feeder. This is particularly true for R-DER spread throughout the feeder; however, even fault current from U-DERs located at or near the head of the feeder may provide little fault current through the transmission-distribution (T-D) interface.

Typically, load is not modeled in short-circuit analysis because its impact and significance to overall BPS fault current levels is very low. However, in localized areas or systems dominated by DERs, fault current from DERs may play a more significant role in overall fault current contributions. In these cases, it may be deemed necessary to model DERs for short-circuit analysis. It is important to note, however, that in cases where DER contribution to BPS fault current is deemed necessary to model, the response from end-use loads (particularly motor load) should also be considered. This is analogous to short-circuit studies performed at large industrial facilities, where the effects of motor loads on fault current cannot be overlooked since they have a significant impact on proper relay operation. The same concept applies to the BPS in a system dominated by DERs.
Aggregate DER Data for Short-Circuit Studies

In cases where DER data may be necessary for short-circuit studies, the TP and PC will need to establish requirements per MOD-032-1 Requirement R1 around what types of short-circuit modeling data needs to be provided by the DP. These requirements should be as clear and concise as possible to help facilitate this data transfer. It is likely that many TPs and PCs fall into either categories 2 or 3 of Table 4.1 today. Where DER data may be needed for forward-looking short-circuit studies, the following information may be needed regarding the aggregate DERs:\(^{61}\)

- Continuous MVA rating of aggregate DERs
- Vintage of IEEE 1547-2018, and settings applicable for DER tripping and momentary cessation (i.e., would the DER trip or cease current injection for fault events)
- Assumed effective fault current contribution at a specific timeframe(s)\(^{63}\) during the fault
- Assumed phase relationship between voltages and currents

Example where DER Modeling Needed for Short-Circuit Studies

One example where U-DER data may be needed is for local breaker duty short-circuit analyses. Consider Figure 4.1 showing a 230/69 kV network with a hypothetical yet possible situation where breaker underrating could happen. At the MK-69 bus, before the addition of DER #1 (20 MW) and DER #2 (20 MW), the breaker at MK-69 (shown in red) connecting the circuit to GY-69 is at 99.4% of interrupting duty when a fault is applied on the MK-69–GY-69 circuit (shown in the figure as well). If the DER fault current contribution was ignored, then short-circuit studies would remain unchanged since the contribution from DERs would not be modeled. However, if the 40 MW nameplate capacity of DERs is modeled to provide 1.1 pu fault current, then the breaker could be underrated as the interrupting fault duty jumps to 101.1%.

Figure 4.1: Example Network for Breaker Underrating Example

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\(^{61}\) Again, this is likely on a T-D transformer basis, per TP and PC data reporting requirements.

\(^{62}\) Based on minimum requirements for modeling voltage-controlled current sources in short circuit programs.

\(^{63}\) These may include sub-transient, transient, and other applicable time frames based on TP and PC modeling and study techniques.
Chapter 5: GMD Data Collection Requirements

NERC TPL-007-3 requires TPs, PCs, TOs, and GOs owning facilities that include power transformers with a high-side, wye-grounded winding with terminal voltage greater than 200 kV to perform GMD vulnerability analysis. The GMD vulnerability assessment is a documented evaluation of potential susceptibility to voltage collapse, cascading, and localized damage to equipment due to GMD events.65

During a GMD event, quasi-dc GICs flow through transmission circuits and return through the Earth by grounded-wye transformers and series windings of autotransformers that provide a dc path between different voltage levels. DC current flow through transformers produces harmonic currents that can increase transformer reactive power consumption and may cause hot-spot heating that potentially leads to premature transformer loss of life or failure. Further, harmonic currents propagate through the power system, can cause BPS elements to trip, and may be a potential susceptibility for aggregate DER tripping.66

In performing GMD vulnerability assessments, TPs and PCs use a dc-equivalent system model (GIC system model) for determining GIC levels and a steady-state power flow model for assessing voltage collapse risks. Current GMD vulnerability assessment techniques per TPL-007-3 do not call for modeling the distribution system or including DER data.67 Typically, only higher voltage BPS elements are represented in these simulations because long transmission circuits with low impedance generally produce the highest levels of GICs. Further, delta transformer windings block GICs from flowing since they do not create a return path for GICs to flow. Many T-D transformers are delta-wye (grounded) and therefore only GICs could flow on the distribution side. However, distribution circuits are relatively short and have high impedance; therefore, GMD events are not a significant focus.

Based on these findings, there is currently no need to model the distribution system, end-use loads, or aggregate DERs for the purposes of vulnerability assessments in TPL-007-3. Regardless, as the penetration of DERs continues to increase to higher levels, these assumption may need to be revisited in the future.

Key Takeaway:
There is currently no need to model the distribution system, end-use loads, or aggregate DERs for the purposes of vulnerability assessments in TPL-007-3.

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66 While local distribution-related issues may arise, there is no evidence that widespread distribution issues could manifest and impact the BPS during GMD events. However, a large GMD event may cause severe harmonic distortion on the distribution system. The main concern related to DER would be potential tripping caused by harmonic distortion. However, further research is needed in this area to understand the extent to this risk. Refer to the EPRI report for more details: https://www.epri.com/#/pages/product/000000003002017707/?lang=en-US.
Chapter 6: EMT Data Collection Requirements

As the penetration of BPS-connected inverter-based resources continues to grow, EMT modeling and simulations is becoming increasingly critical for ensuring reliable operation of the BPS. Entities are developing interconnection requirements for BPS-connected inverter-based resources to ensure that modeling information is available to perform EMT simulations when needed. As the penetration of DERs continues to grow as well, there may be situations where studying reliable operation of the BPS, including networked sub-transmission systems, will require modeling DERs. If industry is moving towards performing EMT simulations for BPS-connected plants (for example, on the order of 50 MW) because of known reliability issues, it warrants similar EMT simulations to be performed for pockets of high penetrations of DERs as well (for example, a small geographic region of 50-100 MW of DERs). This section describes the situations where representing DERs in EMT models may be needed by the TP and PC, and steps that can be taken to help facilitate development of these models in coordination with the DP.

DER Modeling Needs for TPs and PCs

EMT simulations are used to study very detailed interactions between grid elements and controls, and can capture potential reliability issues that may not be detected with RMS positive sequence tools. As the penetration of inverter-based resources grows, EMT simulations become increasingly important in many areas. In most cases, EMT simulations are needed in pockets of the BPS where the localized penetration of these resources is high. Examples of situations where these types of studies are needed include, but are not limited to, the following:

- High penetration pockets of inverter-based resources, particularly when DERs replace or displace synchronous generation in the local area. The lack of synchronous resources presents challenges related to synchronous inertia and low short circuit strength conditions. As these pockets approach 100% of DER penetration, potential reliability risks may arise that require EMT simulations to identify.

- Ride-through performance for DERs (and BPS-connected inverter-based resources) becomes critical during severe voltage excursions in pockets of low short circuit strength. This often requires EMT simulations that represent the specific phase-based protection aspects and inner control loops of inverter controls.

- Analysis of voltage control performance and coordination of voltage control settings across many DERs and the BPS. Areas with high penetration of DERs may need to rely on dynamic reactive support on the BPS, and may see greater variability of voltages at the distribution level. This will need to be coordinated, and EMT simulations are more effective at identifying issues than RMS positive sequence simulations.

- Pockets of high penetrations of inverters are prone to control interactions between neighboring facilities or with the grid. In addition, these pockets may present control stability issues for inverter-based resources that require attention for aspects of large disturbance behavior such as active and reactive power recovery and oscillations. When DERs represent a substantial amount of generation in a localized area, these issues may arise and could impact the BPS.

- Selection of control modes such as momentary cessation and other ride-through performance, and reliable operation of the overall area or region (including parts of the BPS) may be necessary under high DER penetration conditions.

There is no clear threshold for when EMT simulations are needed in any of the situations described above. TPs and PCs have developed various metrics to identify potential conditions that warrant closer attention through EMT simulation techniques.

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69 https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Item_4a._Integrating%20Inverter.-Based_Resources_into_Low_Short_Circuit_Strength_Systems_-_2017-11-08-FINAL.pdf
Mapping TP and PC Modeling Needs to DER Data Collection Requests

EMT models are detailed representations of system elements used for identifying a wide range of potential issues, as mentioned above. However, representing end-use loads or aggregate DERs, in many cases, requires some assumptions and estimations be applied. While use of generic models for EMT simulations is typically discouraged for BPS-connected resources, the data for creating EMT models (or the EMT models themselves) may not be available for many types of DERs. However, for cases where the TP and PC have determined that an EMT study involving aggregate DERs may be needed to ensure reliability of the BPS, the following recommendations are made:

- **R-DER:** Small, retail-scale DERs across the distribution system (e.g., rooftop solar PV) will most likely not have DER models or information available, nor is this level of detail needed for a BPS EMT simulation. Rather, generic EMT models can be used to represent the aggregate amount of DERs at locations similar to how steady-state powerflow and RMS positive sequence simulations are performed. For the most part, the information needed to formulate an EMT model of aggregate DERs will mirror the information needed for RMS positive sequence dynamic models, including:
  - Type of DER and vintage of IEEE 1547
  - Disturbance ride-through behavior including use of momentary cessation
  - Voltage, frequency, phase angle, and ROCOF trip thresholds
  - Dynamic and steady-state voltage control performance expectations

- **U-DER:** Some entities have implemented the same modeling requirements for larger inverter-based U-DERs as for BPS-connected inverter-based resources; namely that an EMT model may be requested from the TP or PC and will need to be supplied by the DER owner in coordination with the manufacturer, to the extent possible. This is typically applicable only for U-DER facilities, say, greater than 1 MVA in capacity. For substations with multiple inverter manufacturers, the TP and PC may aggregate these models into distinct U-DER resources for the more predominant inverter types. On the other hand, other entities may deem that generic models may be suitable for U-DERs as well, and the information described above could also apply for developing EMT models for U-DERs.

Industry is still grappling with the growing need for EMT simulations in many areas, and new findings and recommendations will continually be developed. It is clear, however, that EMT simulations are need for appropriately identifying specific reliability issues; therefore, the TP and PC should coordinate with the DP or other external entity to gather EMT modeling information to the extent possible, when needed.
Appendix A: References

Appendix B: Data Collection for DER Energy Storage

Collecting data for DER energy storage is similar to collecting data for DER generating resources. However, it is worthwhile to highlight considerations that should be made when developing data reporting requirements for collecting DER data that ensure clarity for representing energy storage for planning assessments. This appendix describes at a high level some of the considerations that should be made, and also describes specific data points that are unique to energy storage from a data collection standpoint. While there are many types of energy storage technologies available today, this section focuses mainly on inverter-based battery energy storage since it is the most prominent form of DER expected in the foreseeable future and widely observed in DER interconnection queues today.

Existing large, synchronous DERs may need to be modeled explicitly based on TP and PC modeling practices, and the TP and PC should have these considerations listed in any modeling requirements. Note that, today, electric vehicles (EVs) are likely modeled as part of the load since most existing EVs do not provide storage capability, and demand response actions (such as reduction of heat pump loads) are also not generally modeled as energy storage in planning models. Lastly, there are different ways to model energy storage DER – as part of the composite load model, as a standalone resource, or lumped with other forms of DER. This guideline focuses on data collection necessary for the TP and PC to be able to make appropriate modeling decisions based on their own practices.

Considerations for Steady-State Modeling

Energy storage DERs are likely modeled similarly to other DERs in planning base cases, although modeling and study practices may vary based on whether the energy storage is assumed to be charging or discharging. Energy storage DERs will need to be accounted for to ensure appropriate modeling based on TP and PC modeling practices. The following considerations should be made by the TP and PC, when developing data requirements for DER information with the DP (note that these considerations build off of Table 2.1):

- **Location**: TPs and PCs will need to know the general location, at least mapped to a T-D transformer, of energy storage batteries such that they can be modeled appropriately in planning base cases (in conjunction with other DERs and end-use loads). Separating DER generation and energy storage for collecting accurate DER data from the DP in coordination with any other state-level agency or regulatory body is a prudent step for effectively developing base cases based on TP and PC practices.

- **Type of DER (or aggregate type)**: As stated, differentiating out DER generators, DER energy storage, and hybrid facilities will be needed for the purposes of aggregate modeling of DERs in the future.

- **Transformer Information**: If the energy storage DER is considered a U-DER, a step-up GSU may be explicitly modeled by the TP and PC based on their modeling practices. In this case, transformer information will be needed by the TP and PC for the energy storage DER facility.

- **Historical DER output profiles**: The output profiles for energy storage DERs are likely much different than for DER generation, such as synchronous or solar PV DERs. As such, the TP and PC will need to determine a suitable assumption for output profiles for each to create planning base cases. Therefore, some information will be needed on energy storage DER output profiles. Some questions for consideration include, but are not limited to, the following:

  - What percentage of energy storage DERs are participating in wholesale markets, and can the markets in which those DERs are participating provide any useful information in terms of how the energy storage DERs may be dispatched?
  - What percentage of energy storage DERs are operating based on retail signals such as time of use charges or other third party signals that drive charging and discharging at specific hours of the day? Most

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70 These practice may include explicit modeling of the plant main power transformer and equivalent representation of individual pad-mounted transformers within the U-DER facility, or may be simplified to an equivalent representation of transformations. The TP and PC should have modeling requirements that clarify this point.
commonly, the assumption is made that energy storage DERs will charge during light load conditions and discharge during peak loading conditions; however, various entities have experienced energy storage charging patterns that do not conform to these basic assumptions. Therefore, the DP in coordination with any other state-level agency or regulatory body will need to coordinate with the TP and PC to determine how these patterns could affect transmission planning processes and practices.

- **DER Status:** It is not likely that additional considerations will be needed for energy storage DERs related to status (on-line versus off-line). However, TPs and PCs will need to consider for whether the aggregate amount of energy storage DER is charging or discharging.

- **Maximum DER active power capacity (Pmax):** As mentioned, differentiating the amount (capacity) of energy storage DERs will enable the TP and PC to model these resources, as needed. Therefore, it is not likely that additional information would be needed for energy storage DERs.

- **Minimum DER active power capacity (Pmin):** Energy storage resources have the ability to charge, unlike DER generators, and therefore energy storage DERs will have a modeled negative Pmin value in the base case. Therefore, separating out energy storage DERs will enable reasonable representation of Pmin values in the base case.

- **Reactive power-voltage control operating mode:** Similar to DER generators, it is important to understand any interconnection requirements and operating practices for the DERs regarding their reactive power-voltage controls. Knowing this information, TPs and PCs will be able to model them accordingly.

- **Maximum DER reactive power capability (Qmax and Qmin):** If energy storage DERs are providing any voltage support, then these resources will need an associated Qmax and Qmin value in the base case, and the DP will need to coordinate with the TP and PC to understand appropriate assumptions.

### Considerations for Dynamics Modeling

Energy storage DERs represented in the planning base case should have some aggregate dynamic model that captures the general behavior of these resources during abnormal BPS conditions. The DER_A dynamic model is used to represent inverter-based DERs, which energy storage DERs fall under. However, the parameter values for the DER_A dynamic model that would need to be modified are fairly minimal. These include, but may not be limited to, the following (note that these considerations build off of Table 3.1):

- **Typeflag:** Explicit modeling of energy storage DER requires consideration of the typeflag parameter of the DER_A dynamic model. Refer to software model specifications for how to set typeflag to emulate an energy storage device.\(^7\)

- **Pmin:** The Pmin will need to be modified to accommodate the capability to absorb active power (i.e., negative Pmin), based on the expected energy storage capacity being modeled. If the voltage-dependent current limits (absolute value, not sign) are different in charging versus discharging mode, then the values of the VDL tables will need to be changed based on operating mode assumption.

- **Frequency Response Parameters:** If the energy storage DER is providing frequency response capability, in either the upward or downward directions, or both, then these parameters will need to be configured accordingly. This could be different than the aggregate DER generation model. For example, R-DER may not be providing underfrequency response; however, larger energy storage DERs may be providing this capability and service to a wholesale market.

- **Frequency and Voltage Ride-Through Capability:** TPs, PCs, and DPs should consider whether any different requirements are in place for DER energy storage versus DER generation; however, this is not likely in most cases once the new IEEE 1547-2018 inverters become available. Consider whether the fractional

\(^7\) Based on the specification for the DER_A dynamic model: [https://www.wecc.org/Reliability/DER_A_Final_061919.pdf](https://www.wecc.org/Reliability/DER_A_Final_061919.pdf).
reconnection (vfrac) or active power ramp rate (rpwr) may also be different for DER energy storage and generation.

- **Voltage Control Parameters**: TPs, PCs, and DPs should also consider whether any different requirements are in place for DER energy storage versus DER generation regarding voltage control. Voltage control settings that differ across DER energy storage and generation may require modeling details where additional data may be required by the TP and PC.

**Considerations for Short-Circuit Modeling**

As with DER generation, DER energy storage will most likely be inverter-based and therefore will only provide a small amount of fault current to BPS faults. Therefore, the TP and PC can consider whether DER energy storage would need to be differentiated in short-circuit studies based on the materials in Chapter 4. However, it is not likely that DER modeling for short-circuit studies is widely performed in the near-term.

**Considerations for GMD Modeling**

No additional considerations for DER energy storage are needed beyond the recommendations provided in Chapter 5.

**Considerations for EMT Modeling**

EMT modeling considerations for energy storage DER are similar to those described above for dynamics modeling. If the TP or PC determine that DER data is needed for EMT simulations, then differentiating DER energy storage and DER generation is recommended. Larger U-DER (either DER generation or DER energy storage) may require more detailed models than aggregate amounts of R-DER (again, either DER generation or DER energy storage).
Appendix C: DER Data Provision Considerations

DPs have some accounting of aggregate DER, in coordination with the TP and PC data requirements per MOD-032-1. A timeline and projection of aggregate DER growth at each T/D transformer is of particular importance for steady-state, dynamics, short-circuit, and EMT modeling purposes. The transfer of aggregate DER data to the TP and PC for modeling is ultimately critical to the reliable operation of the BPS, particularly moving forward as the penetration of DERs continues to grow.

In some cases, however, the DP may not have aggregate DER information readily available to provide to the TP and PC for modeling purposes. This may be particularly true to future projections of DERs most relevant for TPs and PCs for planning purposes. External parties such as state regulatory bodies like the California Energy Commission and Minnesota Public Utilities Commission, as well as R-DER and U-DER installers, may have more detailed information pertaining to wide-area DER projections. Thus, TPs and PCs will benefit from collaborating with DPs to determine if external parties can be engaged to help support the provision of DER data for modeling aggregate DER by the TP and PC.

TPs and PCs should consider developing an overall framework for the process DER data collection. In particular, TPs and PCs will likely benefit by establishing data specifications that leverage the respective strengths of both DPs and DER installers for existing facilities as well as other sources for forward-looking projections. Further, DPs could establish requirements that require DER installers to provide information to the DP, TP, and PC during DER interconnections. DPs may consider working with state regulators and other agencies to determine the most effective method for establishing these types of requirements. If alternative sources of DER data are readily available in higher quality forms for use by the TP and PC, these should be leveraged to the extent possible for use in planning BPS studies. Diagrammatic examples accompanying data specifications will likely reduce any confusion or misunderstanding between entities. Collaborative processes by which data specifications are determined and data collection frameworks are designed will likely result in higher quality information transferred from the DP, and other applicable external entities, to TPs and PCs. Higher quality information for the purposes of modeling will support reliable operation of BPS.

AEMO DER Registry Case Study

A recent example of external DER data that can be useful for modeling purposes comes from the Australian Electricity Market Operator (AEMO) DER Register. Under the National Electricity Rules that govern Australia’s major electricity market across the east and south eastern states, all Network Service Providers (NSPs) to provide or update “DER generation information,” defined as “standing data in relation to a small generating unit” for any DER rated below 30 MW. To facilitate the collection of DER generation information, AEMO worked with NSPs, DER installers, and other stakeholders for over a year to develop a secure online DER data submission process. AEMO requires submission of DER generation information at the National Metering Identifier (NMI)-level, simultaneously leveraging the relative strengths of NSPs and installers as DER data providers. Figure C.1 illustrates AEMO’s expectation for NSPs and installers to have different types of DER data, which AEMO determined are necessary to model and plan for the impacts of aggregate DER (options are allowed as to how the data is provided into AEMO's system).

---

72 https://www2.energy.ca.gov/renewables/tracking_progress/documents/renewable.pdf
73 https://mn.gov/puc/energy/distributed-energy/data/
The work flow for joint submission of DER generation data from the NSP and DER installers, ultimately resulting in a DER installation certificate, is shown in Figure C.2. The work flow diagram emphasizes the importance of a collaborative specification for attaining DER generation information. The distinction between “as-approved” and “as-installed” information is crucial; one subset of data is likely readily available to NSPs, whereas another subset of data is likely readily available to DER installers (see Figure C.3).
ensure that the data requests are completed consistent with AEMO’s specifications. The submission process is supported by an Information Collection Framework that emphasizes four principals:77

1. Data collected should initially comprise of the statically configured, physical, DER system, at the time of installation.
2. Have regard to reasonable costs of efficient compliance compared to the likely benefits from the use of DER generation information.
3. Best practice data collection should be implemented, wherever possible, leveraging existing data collection methods.
4. Balancing information and transparency, the DER register should be accessible and easy to use, while confidentiality and privacy are protected.

NSPs in the NEM have varying levels of sophistication when it comes connection approvals and data collection. As a result, AEMO’s DER Register system is designed with optionality to provide and validate DER data via API directly from the NSP, AEMO’s Web Portal or via smart-phone applications that many DER installers are already using to register an installation to access government subsidies. These options enable the minimum change and cost for implementation for each NSP. The full design of the Information Collection Framework and related implementation material is also publicly available.78

Figure C.4: AEMO Scenarios of Collecting DER Data
Contributors

NERC gratefully acknowledges the invaluable contributions and assistance of the following industry experts in the preparation of this guideline. NERC also would like to acknowledge all the contributions of the NERC System Planning Impacts of Distributed Energy Resources Working Group (SPI DERWG) as well as the NERC System Protection and Control Subcommittee (SPCS) and leadership of the NERC Geomagnetic Disturbance Task Force (GMDTF).

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Reliability Guideline: Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System

Action
Approve

Background
In November 2017, NERC published the Special Reliability Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System1 ("Report"). In the Report, NERC made numerous recommendations for assessing disruptions to natural gas infrastructure and related impacts to the reliable operation of the Bulk Electric System (BES) in Planning studies, several of which were assigned to the NERC Planning Committee ("PC"). Through subsequent meetings and workshops, it became clear that in order to effectively assess the wide range of BES and natural gas interoperability concerns, a coalition of subject matter experts spanning the various industries would be needed. Thus, the PC established the Electric-Gas Work Group (EGWG) to facilitate this gathering of experts and drive the development of tools and other resources to better educate and inform the electric industry in light of these concerns.

The EGWG held three in-person development meetings as well as multiple conference calls all continuing to build consensus around fuel assurance and fuel-related reliability risk analysis for the Bulk Power System. The guideline was posted for stakeholder commenting November 4 – December 18, 2019. The EGWG considered all comments and developed revisions contained in the attached revised reliability guideline.

All comments and responses are posted on the Reliability Guideline page here.

Proposed motion:
“I move to approve the reliability guideline Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System”
(Note: NERC publications is reviewing the guideline and will make non-substantive edits for format, readability, and style-guide consistency prior to release).

Summary

Draft
Reliability Guideline
Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System
March 2020
Table of Contents

Preface ........................................................................................................................................................................... iii
Preamble ......................................................................................................................................................................... iv
Introduction .................................................................................................................................................................... v

Background ................................................................................................................................................................... v

Chapter 1 : Fuel Assurance .............................................................................................................................................. 1

Fuel Assurance Principles ............................................................................................................................................ 2
Markets .................................................................................................................................................................... 2
Generator Owners/Operators ........................................................................................................................................ 2
Transmission Planners/Planning Coordinators ........................................................................................................ 3

Chapter 2 : Electric Generation Fuel Supply Primer ....................................................................................................... 4

Natural Gas .................................................................................................................................................................. 4
Oil ................................................................................................................................................................................ 6
Coal .............................................................................................................................................................................. 6
Nuclear ........................................................................................................................................................................ 7
Hydro ......................................................................................................................................................................... 7
Solar, Wind, and Other ................................................................................................................................................ 8

Chapter 3 : Fuel Supply Risk Analysis Consideration ...................................................................................................... 9

Natural Gas .................................................................................................................................................................. 9
Oil .............................................................................................................................................................................. 10
Coal ............................................................................................................................................................................ 10
Nuclear ...................................................................................................................................................................... 11
Hydro ......................................................................................................................................................................... 11

Chapter 4 : Fuel-Related Reliability Risk Analysis Framework ...................................................................................... 12

Step 1: Problem Statement and Study Prerequisites ................................................................................................ 13
Step 2: Data Gathering .............................................................................................................................................. 14
Step 3: Formulate Study Input Assumptions and Initial System Conditions ............................................................. 16
Step 4: Contingency Selection ................................................................................................................................... 20
Step 5: Selection of Tool(s) for Analysis .................................................................................................................... 22
Step 6: Perform Analysis and Assess Results ............................................................................................................. 22
Step 7: Develop Solution Framework ........................................................................................................................ 22

Appendix A : Risk Analysis Framework Checklist ...................................................................................................... 23

Appendix B : Items to Include in a Fuel/Energy Survey ............................................................................................ 26
Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
*Because nearly 400 million citizens in North America are counting on us*

The North American BPS is divided into six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.
Preamble

It is in the public interest for NERC to develop guidelines that are useful for maintaining or enhancing the reliability of the Bulk Electric System (BES). The Technical Committees of NERC; Operating Committee (OC), Planning Committee (PC) and the Critical Infrastructure Protection Committee (CIPC) per their charters¹ are authorized by the NERC Board of Trustees (Board) to develop Reliability (OC and PC) and Security Guidelines (CIPC). These guidelines establish a voluntary code of practice on a particular topic for consideration and use by BES users, owners, and operators. These guidelines are coordinated by the technical committees and include the collective experience, expertise and judgment of the industry. The objective of this reliability guideline is to distribute key practices and information on specific issues critical to maintaining the highest levels of BES reliability. Guidelines are not to be used to provide binding norms or create parameters by which compliance to standards is monitored or enforced. While the incorporation of guideline practices are strictly voluntary, reviewing, revising, or developing a program using these practices is highly encouraged to promote and achieve the highest levels of reliability for the BES.

NERC as the FERC certified ERO² is responsible for the reliability of the BES and has a suite of tools to accomplish this responsibility, including but not limited to: lessons learned, reliability and security guidelines, assessments and reports, the Event Analysis program, the Compliance Monitoring and Enforcement Program and mandatory reliability standards. Each entity as registered in the NERC compliance registry is responsible and accountable for maintaining reliability and compliance with the mandatory standards to maintain the reliability of their portions of the BES. Entities should review this guideline in detail and in conjunction with the periodic review of their internal processes and procedures and make any needed changes to their procedures based on their system design, configuration and business practices.

Introduction

The 2019 ERO Risk Priorities Report highlights a wide array of pertinent risks to the reliable operation of the BPS that merit attention and recommends actions that align with those risks.3 Among the diverse risks identified in the report, utilities, generators, and other suppliers are experiencing a number of factors that increase the likelihood of fuel/energy supply challenges, which exemplify the increased importance of thoroughly characterizing cross-sector interdependencies.

The rapid advancement of renewable generation and increased use of natural gas have necessitated the need to reevaluate the methods that the industry has historically utilized to analyze and maintain reliability on the BPS. Increased reliance on natural gas fired generation in various parts of North America will have increased by an estimated 55% over the period 2010–2020. This document will provide entities guidance on how to evaluate such risk factors within their own portfolios to address potential impacts on the BPS.

While this guideline addresses present concerns related to natural gas, it offers a broader perspective offering a definition of “Fuel Assurance” in Chapter 1 and taking a cursory look at all major fuel sources used to supply electric generation in Chapter 2. As each fuel type possesses a variety of limiting factors that affect its reliable delivery through its entire supply chain, Chapter 3 describes specifically what those limiting factors may be and provides guidance to further equip planners with the requisite knowledge to assist in the development of credible fuel supply risks to analyze.

There have been a number of relevant studies performed, especially by Regional Transmission Organizations, Independent System Operators (RTO/ISO), and other organizations4 to analyze and assess generator fuel-related concerns. This guideline combines the experience gained from these studies and outlines a framework in Chapter 4 that may be applied across all NERC regions for effectively evaluating potential reliability risks to the BPS at all times through the lens of Fuel Assurance. Applying this framework for a given area will uncover where credible risks to reliability exist in terms of fuel delivery and will highlight those risks for further analysis and consideration.

Background

In November 2017, NERC published the Special Reliability Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System (“2017 NERC Special Assessment”).5 In that report, NERC made numerous recommendations for assessing disruptions to natural gas infrastructure and related impacts to the reliable operation of the BPS in planning studies, several of which were assigned to the NERC PC.

In July 2018, the PC convened a workshop to highlight ongoing “Fuel Assurance” discussions and studies, and to convene experts from across industries to develop a plan for action. Based on reactions from some workshop attendees, it was clear that some entities desired guidance around establishing “contingency selection” and other assumptions to be used for studying the impact on the BPS from fuel unavailability as well as fuel system disturbances. Transmission Planners (TPs) also desired guidance in identifying potential transmission impacts and how to evaluate the level of risk to the BPS, including the ability to serve load, they should be willing to accept.

In November 2018, the NERC Board approved a set of recommendations developed by the PC to address concerns from the 2017 NERC Special Assessment. One such recommendation was the development of this Reliability Guideline, which was assigned by the PC to the newly formed Electric Gas Working Group (EGWG).

3 https://www.nerc.com/comm/RISC/Related%20Files%20DL/RISC%20ERO%20Priorities%20Report_Board_Accepted_November_5_2019.pdf
4 E.g., The Eastern Interconnection Planning Collaborative Gas-Electric Interface Study performed under the DOE Grant and completed in June 2015
In Appendix E of the 2017 NERC Special Assessment, NERC did an assessment of existing natural gas infrastructure disruption studies conducted by the industry to gain an understanding of existing planning approaches as well as to highlight and promote best practices. As a result of this assessment, NERC presented steps for Planning Coordinators to take when performing future analysis (see below). This guideline is intended to expand upon methods to implement these recommendations.

### 2017 NERC Special Assessment Appendix E Recommendations

- Identify potential natural gas system contingencies and their likelihood of occurrence.
- Assess the impacts for each of the identified contingencies in terms of duration and amount of natural gas supply disrupted.
- Apply the contingency disruptions to the natural gas supply capabilities to calculate the impact on total natural gas supplies and, more specifically, the amount of natural gas available to electric generators.
- Determine the transmission systems ability to transport power to load under these extreme conditions.

Though this guideline discusses planning, commonalities in the assessment techniques, processes, and procedures discussed are applicable to all time frames and may be adopted by more than just TPs and Planning Coordinators (PCs). Terms such as “planner”, “generator owner/operator” (GO/GOP), and “fuel supplier” are not capitalized intentionally so that the concepts presented may be considered and applied in the broadest sense as they pertain to the BES.

The processes identified within this guide may also be applied to those organizations whose resource mix includes entitlement and bilateral transactions that have resource contingencies. Entities with such arrangements can also benefit from recognizing when limitations may potentially impact their grid operations.

This guideline does not create binding norms, does not establish mandatory Reliability Standards, and does not create parameters by which compliance with Reliability Standards is monitored or enforced. The EGWG will work with NERC to gauge the effectiveness of this reliability guideline and support efforts for continued improvement and opportunities for education and information sharing.
Chapter 1: Fuel Assurance

Fuel Assurance is a term that has been utilized in many forums to date but has yet to be given a formal definition. As this guideline directly relates to the conversation taking place across the industry regarding concerns with the rapidly transitioning BPS generation fleet, it is appropriate and timely for NERC to establish its definition for “Fuel Assurance.” Defining this term will ensure consistency and alignment with statements within this guideline and also provide clarity to the industry going forward on the most appropriate areas of focus related to fuel supply risks to generators supporting the BPS.

For the purposes of this guideline, “Fuel Assurance” will be defined as:

**Fuel Assurance:** Proactively taking steps to identify fuel arrangements or other alternatives that would provide confidence such that fuel interruptions are minimized to maintain reliable BPS performance during both normal operations and credible disruptive events.

The criteria to establish the level of confidence referenced in the definition is unique to respective planning areas and is established by planners and/or generator owners/operators based on internal assessments and understanding of their asset characteristics. The role of the Regional Planner in addressing fuel assurance is related to but separate from actions of individual generator owners to assure fuel assurance for their units. The regional planner’s focus is to assess the vulnerabilities of the entire region to withstand fuel disruptions that could impact multiple generators and impact reliable BPS performance. A lack of fuel assurance to a particular generator may affect that unit’s ability to receive revenues from the market or otherwise meet their obligations to their customers but not necessarily impact the provision of reliable service to the entire region. As the fuel mix of generation and wholesale electricity market structures can vary greatly across reliability regions, this guideline does not and cannot prescribe a single approach to the process.

NERC encourages planners to proactively model, evaluate and consider specific BPS impacts based on credible events that could compromise which impacts the provision of reliable service to all or part of the region within the regional planner’s area of responsibility and to develop strategies to mitigate credible risks. Regional planners may consider modeling extreme fuel disruptions to better understand the impact of catastrophic events so that they may prepare for such emergencies. Recognizing that there is no way to anticipate or measure all potential threats and catastrophic scenarios, stakeholders and regional planners should focus on effective measures that will maintain reliable and fuel-secure BPS operations during credible events. Nevertheless, the regional planner should not step into the shoes of individual unit owners and effectively manage the fuel assurance of particular units. Rather, the regional planner should understand the consequences of losing critical generators and take steps to limit the impact of such a loss should a loss of fuel delivery at a particular unit threaten reliability.

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FUEL SECURITY ANALYSIS: A PJM RESILIENCE INITIATIVE

In 2018, PJM performed a fuel security analysis which was designed to stress-test the PJM grid and the fuel delivery systems serving generation in PJM under a series of extreme but plausible future events (using 2023/2024 as the study year). As in any stress test, the analysis was intended to discover the point at which the PJM system begins to be impacted (i.e., when system operators initiate emergency actions) and to identify key drivers of risk. In PJM’s phased approach to addressing the Fuel Assurance issue, Phase 1 involved the fuel security analysis. In Phase 2, which began in 2019, the analysis results are being used to inform PJM’s stakeholder process, which will help to define fuel security attributes for PJM, location and magnitude of how many fuel secure resources or megawatts are needed, as well as determine how to value fuel secure resources. PJM may also use the results of the study to determine how best to incorporate fuel security into other aspects of its operations, markets and planning. The final Phase 3 is a cooperative effort between PJM and United States (U.S.) federal agencies to define and analyze further scenarios based on classified information about credible risks to fuel security that could have impacts on the power grid.

Fuel Assurance Principles

While each reliability area is unique, there are common principles for Fuel Assurance that may be applied more broadly to assist planners in their assessments of the reliability of fuel supply. Below are some examples of actions that various entities may perform to advance Fuel Assurance initiatives.

Markets

RTOs/ISOs that have not already done so could consider additional mechanisms for generators to meet their obligations during reserve shortages (these could be market [e.g., capacity market reforms] or out of market solutions, attempting to avoid out of market solutions where possible or only as a temporary measure while a market-based approach is developed). Such market rules and mechanisms would incentivize generators to maintain or enhance fuel delivery contracts. Additionally, adopting more detailed and timely procedures for communications to members when near-term fuel-shortages/reliability concerns arise (e.g., upcoming shortages or disruptive weather) will allow time for generators to assess and react to fuel supply needs. RTOs/ISOs should also consider other mechanisms that would facilitate greater certainty that generators have reliable fuel options, regardless of market structure (i.e., restructured or vertically integrated).

Generator Owners/Operators

GO/GOPs should seek reliable delivery solutions from both a transportation and commodity perspective. Monitor and evaluate risks associated with varying levels of transportation or delivery options associated with the different types of transportation (Interruptible Transportation, Firm Transportation, etc.). Consider and evaluate a diverse portfolio of products that can be utilized to deliver fuel both reliably and cost-effectively. Examples of these are: delivered bundled products, firm call options for periods of heightened fuel uncertainty, asset management arrangements (AMAs), potential purchases from suppliers with firm capabilities, enhanced infrastructure considerations, storage capacity, LNG options, dual fuel capability, interconnection with more than one pipeline, and on-site fuel reserves. GO/GOPs should consider credible fuel-related contingencies impacting their facilities and provide fuel-related facility outage concerns as necessary to the reliability authority. Lastly, where fuel delivery constraints are routinely evident, GO/GOPs should consider and investigate whether new options for fuel deliveries to a specific facility or their fleet are available.
Transmission Planners/Planning Coordinators

Planners should consider using steps outlined in Chapter 4 of this guideline to develop credible fuel-related contingencies that may be used in planning studies, including but not limited to Reliability Standard TPL-001 (Transmission System Planning Performance Requirements). Any identified fuel-related contingencies should be evaluated for reliability risks and for the planners to determine what (if any) mitigation should be put in place. Planners might consider conducting generator fuel-related surveys to determine potential risks to the fuel supply of the generators. Using the survey data, planners may perform fuel-related reliability risk analyses as described in Chapter 4. Planners should also seek and use experts familiar with regional markets and practices to help interpret and analyze the survey data.

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7 See NERC Standard TPL-001-4 – Transmission Planning Performance Requirements, Table 1 –Steady State & Stability Performance Extreme Events, 3.a.i.
Chapter 2: Electric Generation Fuel Supply Primer

This section describes, at a very high level, the supply chain of each major generator fuel supply type. It describes illustrative challenges that may be encountered between production and consumption, as well as other viable considerations specific to each fuel type. These considerations will assist planners in forming realistic assumptions when developing their own fuel assurance and reliability risk analysis.

Natural Gas

The natural gas supply chain includes three major segments.

1. Production & Processing
   Natural gas is primarily found in reservoir pools and shale rock formations in the earth and brought to the surface through production wells by processing plants that heavily rely on electric power to operate. A series of flowlines and gathering lines then transport natural gas to processing plants. Natural gas is also a byproduct of oil-focused production.

2. Transmission & Storage
   Large-diameter interstate and intrastate pipeline transmission systems transport processed natural gas to end-use customers, such as large-volume customers including local distribution companies (LDCs), natural gas-fired power generation, and industrial users. Alternatively, the processed natural gas may be transported to various storage facilities for future consumption.

3. Distribution
   Smaller-diameter local gas distribution pipelines deliver natural gas to residential, commercial, and industrial customers as well as some natural gas-fired power generators. These customers are often located behind the city gate and are serviced by LDCs.

The Federal Energy Regulatory Commission (FERC) regulates interstate natural gas transportation and storage. The interstate pipeline industry is contract-based, and pipeline and storage companies contract with customers under the terms of FERC-approved agreements and tariffs. Customers select transportation and storage services (firm or interruptible) based on the level of certainty and reliability desired. FERC regulations preclude interstate pipelines from undue discrimination. The pipeline is required to honor all firm service contracts provided force majeure conditions do not impact such service. Therefore, the level of service and priority that a customer selects for delivery of gas is driven by the type of contract it has entered into. In addition to transportation service, customers also purchase the physical commodity to receive gas at contracted points into the applicable transportation agreements and/or at other points of delivery at their respective interconnection points or market center. Larger volume customers (e.g., LDCs and electric generation facilities) may also purchase gas upstream at or near the point of production and contract for pipeline service to transport the commodity to the point of delivery. In addition, based on market conditions, these entities and other market participants may purchase gas at a market center and contract for transportation from that point to a delivery point(s). Also, market participants may purchase a bundled commodity and transportation package from marketers, who deliver the gas using the pipeline capacity for which they have contracted through utilization of the established secondary bilateral market for capacity and commodity. During periods of high usage and system constraints, pipelines may not be able to schedule interruptible customers because capacity is being fully utilized by firm transportation customers. During force majeure events, pipeline companies may also curtail firm customers pro-rata as needed to maintain system integrity.

Intrastate transportation, balancing, storage, and distribution of natural gas by LDCs is subject to state regulation. LDCs are regulated by most states as local gas utilities that have an obligation to serve their firm core customers – the customers for which the system is built to serve reliably (e.g., residential and commercial heating customers).

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8 See 18 C.F.R. § 284.7(a) (3).
Similar to interstate pipeline operations, during periods of high usage and system constraints, LDCs may call on interruptible customers to cease gas usage temporarily. In the event of situations that require action to be taken for reasons that include the need to maintain the operational integrity of the system and/or maintain natural gas service to designated high-priority customers, including “essential human need” customers, state statutes and public utility regulations may allow an LDC to curtail services to some industrial or noncore customers, possibly including power generators. Historically, these state regulatory requirements give the highest priority to residential and small commercial customers without short-term alternatives.

Natural gas pipelines (interstate, intrastate and distribution) are subject to pipeline safety regulations mandated by the Department of Transportation – Pipeline and Hazardous Materials Safety Administration (PHMSA) and to the pipeline cyber-security authority of the Department of Homeland Security – Transportation Security Administration. The majority of natural gas infrastructure is automated, and pipeline operators, storage owners and utilities alike rely on industrial control systems for monitoring and/or remote control; however, the physical delivery systems are mechanical by nature and can be run locally if necessary. Natural gas is moved by using pressure to control the amount entering and leaving the system. Compressor stations are placed throughout the network to maintain pressure at serviceable levels and are in most cases powered by the natural gas in the pipelines themselves. Some stations may have both gas and electric, or even diesel driven compressors for contingency purposes, although other compressor stations may rely solely on electric power. Mechanical regulators are also layered into the pipeline infrastructure to prevent internal gas pressure from threatening pipeline integrity. Typically, limited supply and transportation disruptions can be managed through substitution, transportation rerouting, and storage services (though such infrastructure redundancy is much more limited in portions of North America). While the gas transmission system may continue to operate even with the failure of as many as half of the compressors, the pressure may not remain high enough for some power generators to continue to fully operate, depending on the specific pressure requirements of each power generator and its location relative to the failed compressor.9 Many modern gas units have on-site boost compression built in to the unit that is capable of increasing the pressure of the pipeline delivered gas to the combustion inlet pressure required by the unit even with a severe deviation in pipeline pressure. In addition, the gas distribution network can operate largely unattended and without electric power.

Certain characteristics of the natural gas system contribute to its reliability and resilience. The natural gas transportation network is composed of an extensive network of interconnected pipelines that offer multiple pathways for rerouting deliveries in the unlikely event of a physical disruption. Each customer’s ability to use such alternate pathways and capacity to maintain gas delivery will depend upon the rights specified in the customer’s transportation contract.10 In addition, pipeline capacity is often increased by installing two or more parallel pipelines in the same right-of-way (called pipeline loops), making it possible to shut off one loop while keeping the other in service.11 In the event of one or more compressor failures, natural gas pipelines can usually continue to operate at pressures necessary to maintain deliveries to pipeline customers, at least outside the affected segment, subject to the constraints that some power generators may experience due to location and pressure requirements as noted above.12 “Line pack” in the pipelines is routinely used, as necessary, to provide some additional operational flexibility.13 It can facilitate non-ratable flows and support pipeline reliability as a temporary buffer for imbalances. However, line pack must be kept reasonably stable throughout the system to preserve delivery pressure and system capacity. Thus, line pack neither creates incremental capacity, nor is it a

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10 NGC, Natural Gas Systems: Reliable & Resilient at p. 10 (July 2017).
11 Id.
12 Id.
13 Id.
substitute for appropriate transportation contracts, but it can support sustained operation in the short term following a disruption.

Further, the existence of geographically dispersed production and storage, and their location on different parts of the pipeline and distribution system, also provides flexibility to maintain service in the event of a disruption on parts of the transportation and distribution system.  
14

Similarly, producers use various methods to help ensure operational continuity. Because producers have an economic incentive and operational need to continue to flow gas out of the producing field at a constant rate, many techniques are in place to help ensure that operations continue or that any disruption is minimized when a problem arises. In the unlikely event of an unavoidable disruption of supply at a well or in a field, producers have many other options to balance their supply commitments, including increasing production in other areas or using supplies of natural gas in storage.  
15

A disruption to the delivery or supply of natural gas may occur. For example, as NERC has previously reported, disruptions to the fuel delivery may result from adverse events such as line breaks, compressor station fires, well freeze-offs, or storage facility outages.  
16
Similarly, the pipeline system can be impacted by events that occur on the electric system (e.g., loss of electric motor driven compressors).  
17

Additionally, there are two distinct reliability risks associated with natural gas supply: “interruption and curtailment risk.” Operational concerns provide a more typical reason for interruption while a force majeure event would reflect a more extreme curtailment. Curtailment of firm service could occur when an event impacts the scheduled flow of natural gas for various reasons. As stated in Chapter 1, the risks associated with levels of firm or interruptible service should be monitored.

**Oil**

Oil fuel is obtained from the petroleum distillation process as either a distillate or a residual and is then distributed to regional terminals for distribution to end users. Transportation to generation sites is typically by (liquids) pipeline, barge, truck or a combination of the three methods where it is off-loaded into on-site fuel tanks. Each power plant site with storage tanks will have unloading facilities that frequently limit the ability to replenish the on-site storage tanks. Each generator with oil as either the primary or back-up fuel must decide the maximum capacity of the on-site storage tanks as well as the amount of oil fuel that will be kept in inventory. Key factors in how much oil fuel to have on site are the proximity of the regional terminal, the regional terminal capacity, expected run-time, availability of transport tankers (maritime or over-the-road), pipelines, and expected transportation constraints (e.g., roads impassable due to weather conditions or rivers impassable due to ice conditions).

**Coal**

Four major types of coal used to produce electric power, each of which varies in heat content and chemical composition:

- **Anthracite**: The highest rank of coal. It is a hard, brittle, and black lustrous coal, often referred to as hard coal, containing a high percentage of fixed carbon and a low percentage of volatile matter.
- **Bituminous**: Bituminous coal is a middle rank coal between subbituminous and anthracite. Bituminous usually has a high heating (Btu) value and is the most common type of coal used in electricity generation in the United States.

14 Id.
15 Id.
16 2017 NERC Special Assessment at page 7
17 Id.
• Subbituminous: Subbituminous coal is black and dull (not shiny) and has a higher heating value than lignite.
• Lignite: Lignite coal, aka brown coal, is the lowest grade coal with the least concentration of carbon.

Coal is extracted from surface and underground mines in various regions around the U.S. and the world, after which it is crushed and washed in preparation for transport to power plants. Transportation is typically by rail, barge, or truck. Coal may be delivered directly to a power plant or to a nearby unloading terminal from which it proceeds to the power plant by truck or conveyance system. At the plant, coal is stored on-site in piles to be used as needed for generation, typically in an amount sufficient for several weeks to several months of operation. Coal can be transported by rail using tariff rates shipment-by-shipment, or under customer-specific short- or long-term rail contracts. Contracts may provide discounts when compared to the tariff rates but require volume commitments over a specified period of time.

**Nuclear**

Nuclear plants are refueled every 18-24 months. Required outages cannot normally be delayed. Nuclear plants need to maintain certain reactivity levels in nuclear fuel. At times, this reactivity requirement has led to units derating in shoulder months in order to conserve fuel and be available to operate 100% during peak months.

Four major processing steps must occur to make usable nuclear fuel: mining and milling, conversion, enrichment, and fuel fabrication. Uranium used in power plants comes from Kazakhstan, Canada, Australia, and several western states in the U.S.. Major commercial fuel enrichment facilities are in the U.S., France, Germany, the Netherlands, the United Kingdom, and Russia.\(^{18}\)

Fuel is stored on site at nuclear plants which are built to withstand significant physical events, including weather, seismic, and other types of natural disaster. Robust security measures (e.g., armed security officers), physical barriers, and intrusion detection and surveillance systems are required by licensees.\(^{19}\)

Nuclear facilities in the U.S. are regulated by the Nuclear Regulatory Commission (NRC). Nuclear power plants must show that they can defend against a set of adversary characteristics called the Design Basis Threat (DBT). DBT imposes security requirements on nuclear power plants based on analyses of various factors, such as the potential for a terrorist threat. The DBT is regularly evaluated by the NRC for updates and alignment with the threat environment.

Nuclear facilities use digital and analog systems to monitor, operate, control, and protect their plants. Digital assets critical to plant systems for performing safety and security functions are isolated from the external networks, including the Internet. This separation provides protection from many cyber threats.

**Hydro**

An integrated hydro-electric system, like those found in the Pacific Northwest, is more frequently energy limited than capacity limited from its mix of storage and run of river projects. The storage projects fill and draft annually and tend to have a steady discharge. Fluctuations in discharge (generation) are usually driven by flood control and downstream water temperature objectives. The run of river projects more closely follow demand as the projects fill and draft daily. However, run of river projects have limited storage to meet demand because the water needs to be in the right place(s) at the right time(s). Hydro-electric generation also has many non-power objectives that can limit hydro-electric power production (e.g., lake level management, recreational use, etc.). Information sharing, communication and coordination is critical across different hydro projects, Utilities, States, and Countries.

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\(^{18}\) [https://www.nei.org/fundamentals/nuclear-fuel](https://www.nei.org/fundamentals/nuclear-fuel)

Solar, Wind, and Other
Technologies such as BPS-connected solar photovoltaic and wind generation have rapidly grown and will likely continue to contribute considerably to the resource mix of the future. These resources are asynchronously connected to the grid and only interface with the BPS through power inverters. This rapid adoption of inverter-based resources has presented new opportunities in terms of grid control and response to abnormal grid conditions, and has necessitated the standardization of performance characteristics for inverter-based resources. NERC produced a Reliability Guideline for this purpose in late 2018. The "fuel" for wind and solar generation are the wind and sunlight that are effectively limitless, but are only available as weather permits.

Other technologies such as battery storage are still in early stages of development and deployment and will require further evaluation and consideration as they mature.

Chapter 3: Fuel Supply Risk Analysis Consideration

This chapter describes, at a high level, the supply chain considerations of each generator fuel supply type that will assist planners in forming realistic assumptions when developing their own fuel-related reliability risk analysis.

Natural Gas

While the natural gas industry does not have a history of being susceptible to failure in general or to wide-spread failure from a single point of disruption because of the dispersion of production and storage, redundancies due to the integrated pipeline and distribution network, and its low vulnerability to weather-related events, a credible scenario to examine is a temporary outage of a section of a single pipeline or a delivery point. When considering such a natural gas supply disruption within a given region, the examination would not just be limited to the loss of the gas supply but also the associated loss of electric generation and any ancillary needs such as the loss of electric gas compression.

Planners should fully examine the credible reliability risks associated with the natural gas supplied to generators within the reliability footprint of the planner. Further, planners should view the system through an “all-hazards” lens and evaluate additional considerations including weather, regional policies and cyber-related risks. The following paragraphs attempt to outline the information that planners should seek to understand as a precursor to a more rigorous fuel assurance and reliability risk analysis.

To begin, planners should seek to understand the strategies employed regarding natural gas supply to each generator within their reliability footprint and any applicable regulatory requirements. This could include regular and emergency transportation/service agreements, call options, or other marketing arrangements being employed by the GO/GOP to meet its resources capacity obligations. This examination could also include reviewing access to on-site fuel storage (e.g., oil fuels, propane, liquefied natural gas (LNG) or compressed natural gas (CNG)), access to off-site storage, access and availability of an alternate pipeline connection, and the availability of non-firm gas services and supply. Planners may also consider the alternative fuel capability of the generator, how any such alternatives are contracted and managed, and any environmental and regulatory requirements that may limit the use of the alternative fuel.

The PJM study “Fuel Security Analysis: A PJM Resilience Initiative” investigated the two following natural gas “disruption” scenarios with different recovery expectations:

<table>
<thead>
<tr>
<th>“Line Hit” such as an excavating crew accident</th>
<th>“Other” such as corrosion</th>
</tr>
</thead>
<tbody>
<tr>
<td>This type of disruption is easily identified, isolated to a smaller area requiring repairs, and would only cause about a 5-day disruption.</td>
<td>This could take longer as investigations are needed over a larger area and will likely be a more “sustained” type of outage.</td>
</tr>
</tbody>
</table>

Planners should examine for each generator its potential physical access to supply (including access to pipeline, distribution and storage facilities), amount of capacity subscribed and available capacity at each supply facility, and the ability of the facility to meet daily and seasonal demand swings. In addition, planners should review potential curtailments to key supply points on their respective transportation agreements (e.g., LDCs needing to redirect supply to “essential human needs” if a severe supply disruption occurs). These details are important in order to formulate

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21 Although it is noted that prior to shale gas, hurricanes in the Gulf of Mexico caused large amounts of supply to be shut-in.

22 Storage facilities are different in the various regions of the US; therefore, understanding the configuration, operation, and services available in the different regions is recommended.
supply alternatives to consider when examining a possible supply shortage or failure. While physically severing an interstate pipeline is very uncommon, it can occur such as in the event of third-party damage. Furthermore, a facility may need to be taken out of service for maintenance. Other considerations include specific pipeline resilience, geography, and potential state or federal restrictions on pipeline expansion, competition for supply with heating and industrial demands, and upstream demand that may impact the region. Environmental permits such as those allowing streambed alteration, for example, may be required and will vary by repair required and specific location. Quick agreement on any environmental mitigation measures will speed obtaining those permits. As noted previously, the planner’s role is to have specific knowledge of the fuel assurance of individual generators in order to be able to assess, over the larger footprint, whether any fuel assurance problems at a particular unit can impact the maintenance of reliability to the region as opposed to just impacting the deliverability of that particular unit. Planners need to recognize this distinction so as to avoid taking on management responsibilities that more appropriately lie with the individual unit owner.

In order to assess the foregoing, data can be obtained from certain public sources. FERC regulations and the business practice standards of the Wholesale Gas Quadrant of the North American Energy Standards Board (NAESB) applicable to natural gas pipelines, which are incorporated by reference into FERC regulations, include various posting requirements for regulated pipelines. These standards require the posting of information related to pipeline capacity, gas quality, operational notices, customer indices, and tariff provisions, among other items. The U.S. Energy Information Administration (EIA) also publishes detailed information on U.S. natural gas pipelines and underground storage. FERC also requires that interstate pipelines and certain intrastate and Hinshaw facilities file various forms and operational reports. In addition to the foregoing, the various states also require LDCs to file certain information with the state commissions and/or publicly post certain information. The aforementioned information and data from the applicable generators should also be used to evaluate fuel risk.

Oil
The main risks associated with oil fuel are typically regional depot capacity and transportation (e.g., pipeline, barge, or truck) from the depot to the plant site. Since the oil fuel is stored in tanks, the capacity of the regional depot(s) limits the amount of oil fuel that can be purchased when a need arises. Even in cases where depot levels are adequate to meet the plant needs, the ability to move the oil fuel from the depot to the plant may be challenging due to inclement weather that affects the ability of trucks to safely move the oil fuel. There may also be emissions limitations or other environmental constraints that may limit the amounts or location for liquid fuel storage and/or prevent full utilization of oil fuel in certain areas during portions of the year. For example, oil-fired generation cannot run between May and September in ozone nonattainment locations unless the state governor declares an emergency.

Coal
Risks associated with coal supply are primarily in the transportation of coal from the mine to the power plant. The rail network is comprised of an extensive grid of intersecting and interconnected tracks which offer multiple pathways for rerouting deliveries in the event of a physical disruption, but temporary slow-downs or disruptions to supply can occur in the rail system due to weather (e.g., floods or snow), derailments, or track repairs. Barge transport can be temporarily impaired by icy, low-level, or flooded conditions on river systems. Generators rely on their on-site coal supply for operation until deliveries can be restored. However, on-site coal supply could be impacted by conditions such as frozen or wet coal. Coal commodity and rail transportation contracts may contain ratability language which states that while there may be some month to month flexibility, shipments must generally be taken consistently. This ratability causes a natural rise and fall of the on-site stockpile based on periods of high and low demand. Any

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23 Such analyses are very similar to what many lenders offering non-recourse finance obtained from an Independent Fuel Consultant.
24 EIA, Natural Gas Storage Report and Wholesale Electricity and Natural Gas Market Data, available at: [https://www.eia.gov/naturalgas/](https://www.eia.gov/naturalgas/).
25 Hinshaw Pipelines are local distribution pipelines or companies served by interstate pipelines that are not subject to FERC jurisdiction by reason of section 1(c) of the Natural Gas Act.
disruptions during the periods of high demand may exacerbate low inventories. Additionally, coal plants are typically optimized to run using only one of the four types of coal, which may limit generation capability if that coal becomes unavailable due to long-term supply or transportation disruptions.

**Nuclear**
As described in Chapter 2, nuclear facilities store fuel on-site in a highly controlled and secure environment. There are many layers of safety at nuclear sites to protect from physical and cyber risks.

**Hydro**
All hydro-electric projects are dependent on upstream sources for fuel supply water. Those sources can be snowpack, other hydro projects, free flowing rivers, lakes, streams, or a combination. Ultimately the source is a function of precipitation. History has shown quite a diversity in the volume of water available for hydro power generation. The total volume can run between 50 and 150% of the expected average. In some areas, much of the precipitation falls in the form of snow and is released as useable water during the spring thaw. The rate of the melt or “run-off” is almost as important as the volume. Slow melts are best, as fast melts can lead to spilling water past fully loaded turbines, or loss of water as a fuel due to lack of storage. Deeply cold winters can also result in frozen rivers and streams, cutting off fuel to downstream projects during times of elevated power demand. Temperature and precipitation are critical factors in the availability of water for hydro power production.
Chapter 4: Fuel-Related Reliability Risk Analysis Framework

The bulk electric transmission system, for the most part, is similar enough from area to area that a specified baseline set of criteria can be defined and followed, resulting in similar and comparable results from transmission planning studies. These planning studies are very well-defined and prescribed in TPL-001; criteria have been developed over many years resulting in multiple revisions to the standard. Even though TPL-001 references a fuel contingency analysis in Table 1 Steady State & Stability Performance Extreme Events as a possible study contingency, the (default) contingency results in only the loss of two generating stations and likely may not represent a significant pipeline segment, compressor station, storage facility, barge transport, or other fuel supply disruption for many systems. This chapter provides details regarding the scope of fuel-related generator outages beyond the minimum requirements for TPL-001 transmission system planning assessments.

The framework presented below does not identify a single methodology, but rather outlines an approach to assist planners in determining what factors may be considered to conduct a meaningful fuel-related reliability risk analysis for the BPS. The actions described are intended to be flexible enough to account for all fuel types, broad enough to support the unique circumstances in each region, and may be performed out of order (or in some cases not at all). This framework does not provide specific solutions or next steps that could be taken after assessing the results of any particular study.

The methodology described in this section may be applied narrowly or across a broad range of credible assumptions as determined by the planner performing the study. The selected assumptions should ensure that the study is both relevant and meaningful. It may be prudent to subject the BPS system under study to a range of high probability, low impact (HPLI) contingencies as well as some high impact, low probability (HILP) contingencies. Studying HPLI contingencies may shed light on operational needs during such instances and inform changes to processes and procedures to preserve reliability (e.g., improvements in the ability of generators to schedule or contract for natural gas). Even if they are not the primary motivation for the analysis, studying HILP contingencies that stress test the system will bookend your study set and may inform regulators or other interested parties of the reliability impact of such extreme conditions, and also may inform emergency preparedness efforts. Examples of HILP scenarios include severe reduction of non-firm natural gas supply, prolonged pipeline repair, extreme prolonged weather events that affect both supply of and demand for natural gas, or unanticipated low production from variable energy resources (VER).

The examples used throughout this chapter are intended to be illustrative and do not imply or prescribe mandatory actions.

Based on the unique risks in different regions, the fuel-related reliability risk analysis outlined in this Chapter, although not required, is recommended as a best-practice approach for supporting existing studies (such as TPL-001 extreme events analysis), or for conducting a stand-alone analysis. In either case, documentation of each step of the process is critical. Documenting the rationale behind the methodology and assumptions will better inform those reviewing the study both presently and in the future and may also inform subsequent studies.
Chapter 4: Fuel-Related Reliability Risk Analysis Framework

Step 1: Problem Statement and Study Prerequisites

To perform a valid fuel-related reliability risk analysis, there are numerous considerations that should be taken into account that will help shape the direction and results of the analysis. Prior to beginning any analysis, the planner must determine the purpose or goal of the study and, just as importantly, what the study will not do. It is at this point that the criteria, concerns, scenarios and required data will become more evident. Determining which elements of fuel supply risk are to be examined in a single study can be challenging, as different combinations of risks can lead to an unmanageable number of model runs. The following should be considered to help define the study:

- Have a clearly defined goal for the study. Set the criteria of the study and define the criteria for system performance. A study that crosses the threshold of meeting certain criteria will do so when fuel is in short supply, generators are no longer able to run, and there is a supply/demand imbalance. The imbalance can be system-wide or, equally as important, a local area imbalance that results in the potential exceedance of a NERC Reliability Standard defined System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) of the BPS. This philosophy can help determine contingencies that may not be obviously catastrophic, but still highlight issues that may need mitigation.

- Communicate the goals of the study with stakeholders and gain agreement on principal concepts.

- Decide the analysis timeline prior to commencing work. If the problem definition and the solution are going to be two separate phases of a study, set that expectation early in the process.
  - Often, the defined solution is to follow the directives of governing entities (NERC, FERC, Governmental Agencies, State Public Utility Commissions, etc.). If this is the case, that is the goal of the study.

  Example: “The purpose of this study is to determine the minimum required resources to be retained in a capacity auction, accounting for system-wide fuel supply constraints.”

- Clearly state the boundaries of the study. If there are certain aspects that will not be addressed by the study, make that distinction clear as early in the process as possible.

  Example: “The study will be limited only to the generators that are currently in the interconnection queue through 2030.” Or “The analysis being performed will only consider credible single points of disruption in the gas and oil fuel supply chains.”
Step 2: Data Gathering

Data is essential for a valid fuel-related reliability risk analysis. While the planners performing the study are very familiar with the transmission system and the inputs needed to perform traditional studies, there are many considerations outside the normal inputs that are needed for this analysis. Much of the data needed is likely not directly accessible to the planner and will therefore require the assistance of others in their company (e.g., operations personnel) or even fuel suppliers themselves. FERC has through its Order 787 authorized the sharing of confidential information between jurisdictional pipelines and system operators in order to ensure reliability. Planners should consider using that authority to obtain needed information from the pipelines on a cooperative basis. The following is a list of data sources and methods for acquiring data that can be used by planners to collect the information that they need to perform the study outlined in Step 1:

- Coordinate Fuel Assurance assumptions with GO/GOPs.
  - This may be achieved with surveys, which may include, but are not limited to: primary fuel availability, details of fuel supply and transport agreements, usable on-site storage capability, historic inventory levels, resupply and back-up fuel availability and strategy, resource limitations on alternate fuels (MW output, switching time and process details, changes in heat rate), emissions concerns, and staffing concerns.
  - It may be helpful to discuss the formation of such a survey with generator owners/operators and other stakeholders to seek their guidance and expertise on the level of data they may be able and willing to provide.
  - Validate/benchmark that the data received is consistent with the recent operational experiences when possible

Suggestions to Establish and Maintain a Suitable Fuel Survey:

- Consider managing a survey of this type through an established stakeholder forum
  - This will ensure that any changes to the survey are subject to stakeholder discussion and therefore more thoroughly vetted
  - Ensure that the information is reaching the target audience as there can be a disconnect between generator owners/operators and the stakeholder representatives
- Consider hosting additional engagements such as a winter generator readiness seminar
  - This offers the opportunity to discuss with a more targeted audience of generator owners/operators and not just their representatives
- Consider conducting fuel-constrained scenarios as part of your regular training cycle
  - This offers an opportunity to solicit concerns and gather potential impacts of limited fuel supply on system operations across a wide spectrum of electric and cross-sector stakeholders
  - This exercise also has the potential to identify fuel disruption impacts that can be further addressed directly with fuel suppliers to seek actions to mitigate these impacts
  - Gather appropriate fuel supply contingencies (to be further analyzed and filtered in Step 4).
- Coordinate with fuel suppliers or fuel specialists within your company, member companies and/or collaborate with the experts who own and operate the fuel supply chains including, but not limited to, gas and oil fuel pipelines, fuel producers, oil fuel refineries, storage, and trucking companies, rail carriers and ocean or river bound tanker ships/barges. Their input will aid in the assessment of the potential for disruption or failure. It will also lend credence to the assumptions.

- Discuss the fuel supplier’s response plans if fuel supply disruptions were to happen. Rather than rely solely on a hands-off type of study (which still has value), consider the possible mitigating actions of the fuel supplier after the disruptions occur in order to incorporate the impact to the BPS into your analysis. Also consider the time considerations between the disruption and when it will impact the power system. Not all failures have immediate impact.
  - Outreach may include a review of disruption scenarios with each of the fuel suppliers operating within the studied region to assess the viability of both the assumed disruption scenarios as well as the potential downstream impacts.

As an example, question the pipeline companies on what remaining capacity would be available if they lost a particular pipeline segment. Depending on the pipeline configuration, the capacity serving the region’s generators may be reduced by 10%, 50%, or not impacted at all. Each case would produce different input assumptions for the study.

Consider review of internal operational policies and procedures with the pipelines to better understand the impact of those procedures during a fuel supply disruption scenario.
Step 3: Formulate Study Input Assumptions and Initial System Conditions

Assumptions and system conditions may be developed using information obtained from data gathering efforts outlined in Step 2, as well as regional historical experience, to establish relevant scenarios for incorporation into the analysis. These assumptions may be specific (e.g., specific generator outage rates determined from regional historical averages) or expressed in terms of a range (e.g., low, medium, and high ranges of projected generator retirements affecting future fuel mix). Steps to develop these assumptions and conditions for the analysis include but are not limited to the following:

- Determine which fuel(s) to study. When doing so, consider the interdependence of various fuel types and how a large disruption to one fuel source may impact another fuel source.

- Develop fuel assumptions using the best available information.
  - Document fuel supply assumptions for plants where data is not available or up to date to maintain visibility of areas where the study may have weaknesses.
  - Consider fuel supply alternatives such as dual fuel use, and service from alternate pipelines.

- Determine weather and load assumptions.
  - Weather input to the study can be historical normal and extreme weather applied to future scenarios or some version of a weather or climate forecast that describes the study timeframe.
  - For a fuel risk analysis, the system under study is more than just the BPS. There are going to be shared resources between different sub-systems that are interdependent. For example, natural gas is used for both heating and power generation. Understanding the relationship between those two classes of gas demand is paramount when performing this study. Knowing what will happen when the gas system is full due to colder temperatures will define what direction the study goes and, in large-part, the results of the study. Oil fuel works in a similar fashion but with a different mode of transportation. Although pipelines can carry oil fuel, it is typically via truck or barge. But the fundamental concept is the same – when it gets cold and the demand for fuel is up, supply chains become full and resulting supply options and priorities may be unexpected.

- Determine interchange assumptions and interface capability.
  - This should include coordination with neighboring entities to ensure accuracy and agreement of their interchange contribution. Consider whether the conditions selected for your study will also impact an adjacent area’s interchange contribution.
  - A study may assume interchange transaction quantities reflecting the economic interaction between the studied systems and neighboring systems consistent with real-time operations. Alternatively, a historical analysis may be performed...
to determine an upper and lower bound for capacity and energy imports and exports. Coordination with neighboring systems should also include potential impacts of a gas disruption in one region on gas fired generation in adjacent areas—affecting the amount of electric interchange support available.

- Determine generator outage rates and reductions assumptions.
  - Generator outage rates may be defined using standard methods such as EFORd or using a simple analysis of historical performance. Depending on the approach or assumptions, this may deviate from the normally accepted methods.

  *EFORd – Equivalent Forced Outage Rate demand*
  
  the probability a generator will fail completely or in part when needed

  - Take care not to double count outages. Understand that if a generator is out of service due to normal outages, it cannot also be counted as a generator that is out of service due to fuel, and vice-versa.

- Determine assumptions related to VERs.
  - These considerations will be critical in areas with high penetration of VERs where the output range can vary significantly.

  *As of 2019, wind generation output ranged from 0.5 GW to 16 GW in SPP*

- Consider the evolution of generation technology, changes in fuel mix, and the interdependency of future resource installation.
  - The current interconnection queue and integrated resource plans/resource adequacy plans may inform planners of resources to be selected in longer-term analyses.
  - Resource planning forecasts are performed on a regular basis. These studies evaluate the future needs and technologies to meet those needs.
    - These studies may reveal, for example, the likelihood of renewable energy additions resulting in early retirement of coal or oil fuel resources.
    - State initiatives for additional dual-fuel resources, as another example, would likely introduce more gas/oil fuel generators into the interconnection queue.
  - It may be difficult to predict how the future resource mix will vary based on factors such as governmental policy initiatives. Include a range of assumptions for items that have uncertainty.
ISO New England’s Operational Fuel Security Analysis modeled a wide range of resource combinations that might be possible several years into the future. The study examined varying resource retirements, LNG availability, oil inventory, interchange, and renewable resources. In addition to a reference case which incorporated the likely levels of each variable, these input assumptions were varied individually to characterize the sensitivity between unfavorable to favorable boundary cases. Several combination scenarios, examining how multiple related changes would affect the outcome, were also examined which adjusted more than one of the key variables to represent future resource portfolios that could develop and their effects on fuel security.

- Determine performance criteria.
  - For example, if the study being performed contemplates a HILP contingency, perhaps the performance criteria would be that 90% of firm load is maintained for a short period of time. However, when HILP is studied, it should be done for emergency preparedness and not for measuring the reliability of specific system resources. Another consideration in this scenario would be acceptable system ratings and limits. If the study being performed contemplates a HPLI contingency, perhaps the performance criteria would be set to a base case, or up to unavailability of interruptible load.

- Determine the study frequency, outlook, and duration according to the risks identified through data gathering. Depending on the assumptions, electric system, or fuel supply chains that may have changed, the planner should use engineering judgement and historical information.
Chapter 4: Fuel-Related Reliability Risk Analysis Framework

For choosing a study frequency (i.e., how often the study is performed), consider the following:

- Operational time frame studies could be performed on a weekly, or monthly basis, or other near-term periodicity. For example, one existing analysis involves a winter weekly or non-winter bi-weekly energy study that is used on an ongoing basis for operations planning.
- Seasonal studies could be performed periodically in the pre-winter or pre-summer time frames in anticipation of the peak load seasons.
- Longer-term studies could be performed annually, every few years, or on a longer-term periodicity as necessary.
- Ad-hoc (one-time) studies could also be performed to assess a unique set of conditions and to achieve specific objectives, and may be more limited in scope.

For choosing a study outlook (i.e., when does the studied time horizon begin), consider the following:

- Short-term operations planning study outlooks (e.g., one-week out, one-month out, six-months out, other-less than a year out) could be used.
- Alternatively, Near-term (1-5 years) or Long-term (6-10 years) transmission planning time horizons, or even greater study outlooks could be used if appropriate for the objectives of the study. For example, one existing analysis was based on a 5-year look-ahead study to assess system resilience under future resource portfolios.

For choosing a study duration (i.e., what is length of the study window), consider the following:

- The duration could be anywhere from a snapshot of the current system to a few days out or even to multiple years depending on what is appropriate for the assumptions or objectives of the study. For example, one existing analysis involves a 14-day study window to model a plausible 14-day extreme cold weather scenario based on historical weather analysis.
- Consider varying durations of fuel disruptions to determine how reliability conditions may change over time given a particular fuel disruption.

ISO-NE performs a 21-day look ahead energy assessment based on the lead time it takes to schedule an LNG and oil fuel truck delivery within the associated region.

- Include any special or additional scenarios or assumptions, for example:
  - Heavy seasonal directional power transfers.
  - Changes in generation mix.
  - Drought or flooding conditions.
  - Changes in fuel supply situation (e.g., closure of refineries or LNG storage facilities, new provisions that limit or prevent local gas and oil fuel transport).
  - System-wide blackout scenario (e.g., scenario studying fuel-related reliability risks to blackstart units and potential impact on system restoration following a blackout).
- Document the rationale behind study assumptions and initial system conditions.
Step 4: Contingency Selection

The data gathered to this point will help to form the basis for contingencies to the fuel supply of the studied system. Some aspects will be known, and some will be assumed. It is possible that not all contingencies will be included in the final study once the probability and credibility of the various scenarios are better established. It may be prudent to establish a priority level for different contingencies based on the planner’s experiences. There are many factors to consider in filtering and selecting the appropriate contingencies to study, which may include but are not limited to:

- The cause of the fuel disruption (which helps with developing proper mitigation).\(^{28}\)
- The frequency with which the disruption has occurred in the past in this or other locations.
- The probability or likelihood that the disruption will occur in the future.
- The expected duration of the disruption based on historical data or reasonable assumptions that acknowledge system improvements over historical data.
  - Fuel disruption duration can be seasonally dependent. For example, a failed fuel delivery system during the high-demand winter months will likely be shorter in duration than a disruption during low-demand periods.
- The amount of fuel supply interrupted. This is a line to be drawn based on relevance to the scenario being studied.

The loss of a single natural gas compressor engine at a station is more likely than the loss of an entire compressor station. Many fuel supply systems contain redundancies and safeguards, making a full outage of service less likely than a partial outage.

- The location of the disruption, even outside of your footprint, as fuel delivery is a worldwide operation.
  - Interdependence of global markets on local systems should not be overlooked. For example, the LNG imports in Japan surged following the 2011 Fukushima nuclear power shutdown.
- The generating units that may be affected by the disruption. Be sure to account for remaining generating capability (if any).
  - Consider alternatives available to impacted generating units such as dual fuel use, and service from alternate pipelines.\(^{29}\)
- The extent or scope of the interruption as to whether it impacts other companies, industries, or other subsystems.

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\(^{28}\) NERC Generator Availability Data System (GADS) data collection was updated for 2020 reporting and going forward cause coding for “lack of fuel” reporting will be much improved.

An example would be if railways in a particular area are washed out due to flooding, re-routing coal delivery around that area will likely be more difficult due to all rail traffic trying to re-route to meet guaranteed delivery dates.

Consider the likelihood of mutual assistance between suppliers. It is within the realm of possibility that a pipeline or oil fuel transporter could suffer a loss of capability and receive assistance from an interconnected pipeline or associated supplier.

Consider if electric load shedding to resolve BPS problems will impact fuel availability or subsequent plant operations.

Consider the impact of electric contingencies on the natural gas system or recovery from a natural gas disruption (e.g., loss of power to electric driven gas compressor stations or transmission contingencies which may restrict the re-dispatch of non-gas fired generators)

- The influence of governmental agencies may also factor into the studied response to contingencies.
  - Consider historical reactions by governing agencies.
  - Consider guidance from governmental agencies such as the potential for cyber and/or man-made threats to fuel delivery systems.
  - Consider working with relevant governmental agencies to share the analysis, develop and gain any needed approval for mitigation measures.

- Non-traditional solutions may be available when directed by emergency management or similar agencies. Conversely, fuel supply could be made unavailable due to decisions made at the governmental level. For example, a port necessary for the delivery of LNG or oil fuel may be shut down following worldwide events that result in a state of heightened security. Another example may be the limited usage of oil fuel unless a special (environmental) waiver is granted by state or federal officials.

Following a pipeline disruption event impacting one of the looped lines in a pipeline segment, PHMSA has historically required a mandatory capacity reduction (typically about 20% firm capacity reduction) in the adjacent non-impacted lines within the same pipeline right-of-way until initial investigation of the incident is complete. PHMSA has also historically restricted access to an affected pipeline segment following an event for safety reasons, delaying immediate restoration efforts by pipeline operators. Both the capacity reduction and delayed restoration due to PHMSA’s response should be considered when studying the gas pipeline contingency impact and duration.

Document the rationale for each contingency selected.
Step 5: Selection of Tool(s) for Analysis

Because of individual system conditions and goals, no single type of transmission system analysis will meet the need of every planner. Therefore, each planner should consider the information gathered in the steps above and choose an analysis tool(s) that can provide information that will allow for a thorough assessment of their supply and transmission systems. This analysis may be power flow, stability or dynamic simulation, production cost modeling, market simulation, oil fuel and gas pipeline hydraulic flow modeling, deterministic vs probabilistic modeling, in-house tools, or any combination of these tools and others.

Regardless of the tool(s) chosen, the rationale for the selection should be documented and reviewed periodically to ensure that the appropriate tools continue to be utilized and provide continuity from the end of the analysis to what was defined in the goals.

Step 6: Perform Analysis and Assess Results

Based on the information from Steps 1-5, system analysis will be performed and assessed. The assessment will evaluate system performance based on the criteria defined in Step 3 to determine if system deficiencies exist and if so, what actions might be considered to improve the observed deficiencies. Every step of the process was defined, including the criteria for system performance. At this point of the analysis, the state of the system is known. If the assessment determines that the system does not meet the prescribed criteria for reliable operation of the power system, and corrective actions are needed, this step is where that would happen.

When delivering the results of the study, consider the audience. Consider their level of knowledge of the system being studied and speak to them at a level they will understand. Use commonly understood terminology, processes, and procedures so that the audience will more likely comprehend the results as intended.

Step 7: Develop Solution Framework

As noted in Step 3, Fuel Assurance studies should be completed on an ongoing basis. Regular analysis will help planners and other stakeholders better understand emerging risks as the power grid undergoes rapid transformation. Planners are encouraged to develop a solution framework to ensure Fuel Assurance in advance of any potential credible reliability issues. It is at this point that the planner should consider engaging governmental agencies that may be able to assist with developing a framework of potential solutions. One example might be contacting state environmental departments to discuss power plant air and water permits should a HILP contingency occur. At a larger regional level, planners are encouraged to consider developing a response and mitigation plan for grid, generator, and gas operators to guide their response to fuel assurance contingencies as identified in Step 4. Further, the development of a communications protocol for grid, generator, and gas operators could benefit the regional response to and mitigation of contingencies as identified in the risk analysis framework. These proactive actions will ensure preparedness and improved situational awareness to handle these potential risks in the future.
Appendix A: Risk Analysis Framework Checklist

This checklist outlines the actions recommended in Chapter 4 into a list that entities may use as a reference when performing their own analysis. As mentioned at the beginning of Chapter 4, the listed steps are intended to be flexible enough to account for all fuel types, broad enough to support the unique circumstances in each region, and may be performed out of order (or in some cases not at all).

**Step 1: Problem Statement and Study Prerequisites**

- Define the study goal (i.e., problem statement)
- Set the criteria for system performance
- Communicate the goals of the study with all stakeholders (electric and fuel suppliers)
- Gain agreement on principal concepts
- Determine the timeline prior to commencing work
- Set the boundaries of the study
- Document agreed upon goals, timeline, boundaries, etc.

**Step 2: Data Gathering**

- Coordinate Fuel Assurance assumptions with generator owners/operators
- Survey stakeholders (see Appendix B)
- Identify relevant fuel supply contingency events
- Maintain documentation for future use

**Step 3: Formulate Study Input Assumptions and Initial System Conditions**

- Determine fuel(s) to be studied
- Determine the interdependence of various fuel types
- Determine how a large disruption to one fuel source may impact another fuel
- If needed, develop fuel assumptions in the absence of actual information
- Determine weather and load assumptions
- Determine interchange and interface capability
- Determine generator outage and reductions rate assumptions (e.g., EFORd)
- Determine assumptions related to variable energy resources
- Determine expected changes in regulatory policy, generation technology, and fuel mix, including the interdependency of resource installation
- Determine performance criteria using stakeholder input (e.g., is load loss acceptable? If so, for how long?)
- Determine study frequency, outlook, and duration
- Include any special or additional assumptions or system conditions, for example:
  - Heavy seasonal energy transfers
## Step 4: Contingency Selection

Filter down identified contingencies. Consider CEII ramifications. Consider factors such as:

- Cause of the fuel disruption
- Frequency with which the disruption has occurred in the past in this or other locations
- Probability or likelihood that the disruption will occur in the future
- Expected duration of the disruption based on historical data or reasonable assumptions
- Amount of the fuel supply interrupted
- Location of the disruption
- Generating units affected by the disruption and remaining generating capability (if any)
- Extent or scope of the interruption (does it impact other companies, industries, etc.)
- Influence of governmental agencies on the response to contingencies
- Document rationale for contingency selection

## Step 5: Selection of Tool(s) for Analysis

Select analysis tools appropriate for the study, such as:

- Power flow
- Stability simulation
- Production cost modeling
- Market simulation
- Pipeline hydraulic flow modeling
- Deterministic vs. Probabilistic modeling
- In-house tools
- Document rationale for selection

## Step 6: Perform Analysis and Assess Results

- Perform analysis
- Document and assess results
- Consider CEII ramifications
Step 7: Develop Solution Framework

☐ Identify potential risks

☐ Develop solution framework as needed and in concert with stakeholders, regulators, etc.

☐ Update existing plans and procedures
Appendix B: Items to Include in a Fuel/Energy Survey

This list is indicative but not all encompassing of the questions which planners may ask of its GO/GOPs depending on the regional study goals and the possibility of regional fuel type generation considerations.

When drafting a survey, consider whether certain questions should be made mandatory. Also consider how to format answer selections; should some be limited to multiple choice, is free form text more appropriate, etc. It will also be important to seek consistency in units of measurement. Make an effort to clarify what units are desired (MW, MWh, MMBtu/day, etc.) so that compiling and analyzing responses is straightforward.

General Information

- Resource information
  - Name
  - Contact
  - Unit identifier
  - Type
- Square footage of fence footprint and what percentage of that space is empty
- Is there a 'bump-up' compressor on-site? How often is it used?
- Net max and min sustainable rating
- Design and/or current operational max/min ambient temperature
- Unit maximum Summer heat rate
- Unit maximum Winter heat rate
- Dual Fuel Unit heat rate on different fuels
- Primary fuel source
- Alternate fuel source
  - Fuel switching requirements, or other considerations
- Date of last MW disruption (or not received) on primary fuel (within the last 5 years)
- Amount of MWs disrupted (or not received)
  - Reason for disruption (or not received)
- Have any fuel supply procurement processes been compromised?
  - For example, limited trucking capability, navigation issues, lack of refinement capability from supplier
  - How often?
  - Any seasonal issues?
- Planned retirement date
- Is staffing required to start the unit?
- Is staffing required to switch fuels?
- Is unit black-start capable or on ISO/RTO system restoration Plan?
Appendix B: Items to Include in a Fuel/Energy Survey

- Consumable item most limiting unit operations (e.g., limestone, chemicals, demineralized water trailers, air or water emission credits, etc.)
- Does the unit/station have existing on-site natural gas compression
- Availability of on-site boost compression
- Is there backup power on-site?
- Are there state restrictions on future use of this unit?
- What is the impact and duration of maintenance shutdowns?
- What is the risk of third-party damage to plant, inventory or transportation types to the plant?

Gas Pipeline Information

- Companies providing physical natural gas pipeline connections
- Critical compressor facilities
  - Identify whether natural gas or electric compressors connected to or required by the unit (if known)
  - Identify if spare compression is available at each compressor site
- Required minimum pressure for full, half, and minimum output
- Required minimum pressure for unit operation (<full output)
- Peak burn rate
- Transportation contract
  - No-notice service, firm, enhanced Firm, secondary firm, interruptible, etc.
  - Transportation contract options available for gas-fired generators
- Commodity
  - Type of service – firm or interruptible, Other?
    - Number of available suppliers
  - Number of pipelines
  - Storage access
  - Asset Management Arrangements or AMAs (e.g., firm delivery expressed in MMBtu/day)
- Seasonal operations considerations
  - Identify any force majeure events called by the pipeline in the last 10 years
  - Identify any critical generators connected to the pipeline that could affect your deliveries
  - What is the nature of the balancing flexibility the pipeline offers you and provide a link to the tariff summary
- Seasonal maintenance considerations

Oil Information

- Limitations on oil burn, number of hours, emissions limitations, seasonality limits
- Number of hours of operation at max/min output on oil
Appendix B: Items to Include in a Fuel/Energy Survey

- Maximum fuel storage capability
- Type(s) of oil (e.g., residual fuel oil, fuel oil #2, etc.)
  - Available usable fuel in storage (typical annual-average value)
- Plans to increase available usable fuel amount
- Assurance level for additional deliveries
- Can fuel be replenished faster than it is used?
- Alternate fuel contracts
- Number of alternate fuel suppliers
- Fuel primary and alternate transportation type (pipeline, barge, rail, truck, etc.)
- Fuel resupply limitations
  - Notice time and delivery time
  - Deliveries expected over given period of time (e.g., how many per day)
  - Proximity of supplier(s)
  - Available offloading facilities
- Does unit need gas to start?
  - If so, is the fuel stored on site?
- Do other units share oil inventory?
- If so, number of hours of operation at max output on shared oil

**Coal Information**

- Maximum storage capacity
  - Current inventory amount
- Inventory resupply plans
- Assurance level for additional deliveries
- Alternative suppliers
- Maximum output that can be sustained indefinitely
- Fuel primary transportation type (barge, rail, truck, etc.)
- Can fuel be replenished faster than it is used?
- Secondary transportation
- Fuel delivery time
- Is delivery on a schedule?
- Scheduled time between replenishments
- Maximum amount delivered in a single shipment
- Typical coal level for replenishment order
Appendix B: Items to Include in a Fuel/Energy Survey

- Units that share coal inventory
- Max runtime for unit with shared fuel inventory
- Does unit need oil or gas to start?
  - If so, what fuel(s) is stored on site?
- What is the unit’s history of freezing coal inventory/piles and are any measures in place to mitigate freezing?

**Alternate Fuel Information**

- Alternate fuel source(s)
- Additional staffing requirements to start the unit on alternate fuel
- Number of hours of operation at max on alternate fuel
- Maximum fuel storage capability
- Available usable fuel in storage
- Plans to increase available usable alternate fuel amount
- Assurance level for additional deliveries
- Alternative suppliers
- Fuel primary transportation type (barge, rail, truck, etc.)
- Can fuel be replenished faster than it is used?
- Secondary transportation
- Alternate fuel resupply time
- Unit net MW max capability on alternate fuel
- Does the unit have to be taken off-line to switch to the alternate fuel?
  - If not, what is the MW output level needed to perform switching?
- Time to transition to alternate fuel
- Date alternate fuel capability was last tested
- Amount of net MW output achieved while on alternate fuel
- Does unit need gas to start?
  - If so, is the fuel stored on site?
- Max number of starts per day on alternate fuel
- Number of starts per week on alternate fuel
- Can generator operate on both fuels simultaneously?

**Environmental/ Emissions**

- Unit environmental/emissions limitations
- Pollutant responsible for most limiting emissions limit
- Limit periodicity of pollutant responsible for most limiting emissions limit
• Pollutant responsible for most second most limiting emissions limit
• Limit periodicity of pollutant responsible for most second most limiting emissions limit
• Other environmental/emissions concerns
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Inverter-Based Resources Performance Task Force
Fast Frequency Response Concepts and BPS Reliability Needs Whitepaper

Action
Approve.

Background
As the bulk power system (BPS) continues to transition towards higher instantaneous penetrations of inverter-based resources, system synchronous inertia will decrease. Smaller interconnections in North America, namely the Texas and Quebec Interconnections, will be affected by this transition first given their lower level of interconnection-wide synchronous inertia. They are taking prudent steps to ensure that frequency does not reach underfrequency load shedding (UFLS) levels for large losses of generation. The high initial rate of change of frequency (ROCOF) caused by decreasing system inertia in an interconnection drives the need for faster energy injection to arrest declining frequency. This type of fast-acting response to changing frequency is considered fast frequency response (FFR), and FFR is increasingly recognized to be an essential reliability service (ERS) for reliable operation of the BPS.

The IRPTF developed a whitepaper to provide fundamental reference materials related to lower system inertia conditions, the increasing ROCOF observed during high inverter-based resource conditions, the need for FFR in some interconnections, and the interrelationship between all factors that affect BPS frequency control. It also provides an overview of the various types of FFR based on different technologies, and it provides a framework for establishing critical inertia conditions based on current system characteristics and existing frequency response capabilities. The paper provides information related to different types of FFR that is based on industry understanding of equipment capabilities and available at the time of writing (late 2019/early 2020); equipment capabilities and operator practices are likely to continue evolving over the next decade.

The Planning Committee and Operating Committee have reviewed the whitepaper and provided comments to the IRPTF. The IRPTF has incorporated the feedback and finalized the whitepaper.

Proposed motion language, if applicable:
“I move to approve the Inverter-Based Resources Performance Task Force Fast Frequency Response Concepts and BPS Reliability Needs Whitepaper.”

Summary
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White Paper

Fast Frequency Response
Concepts and BPS Reliability Needs

NERC IRPTF
White Paper

December-March 2019
# Table of Contents

Preface ........................................................................................................................................................................... iv  
Executive Summary ......................................................................................................................................................... v  
Background .................................................................................................................................................................... vi  
Fundamentals of Frequency Response ........................................................................................................................ vii  
Chapter 1 : Factors Determining Rate of Change of Frequency ..................................................................................... 1  
  System Inertia .......................................................................................................................................................... 2  
  Size of Largest Credible Contingency ....................................................................................................................... 3  
  Speed of Frequency Response ................................................................................................................................. 4  
  Generator Dispatch Considerations......................................................................................................................... 5  
Chapter 2 : Fast Frequency Response Concepts ............................................................................................................. 6  
  Types of FFR Controls ................................................................................................................................................ 7  
  Illustration of System Impacts of FFR ........................................................................................................................ 8  
Chapter 3 : Concept of Critical Inertia ........................................................................................................................... 9  
Appendix A : References ........................................................................................................................................... 14  
Appendix B : Technology-Specific FFR Capabilities ................................................................................................... 17  
  Type 3 WTGs (General Electric) ........................................................................................................................................ 18  
  Type 4 WTGs (ENERCON) ......................................................................................................................................... 19  
Appendix C : Example Calculation of ROCOF ............................................................................................................ 24  
Contributors .................................................................................................................................................................. 26  
Preface ........................................................................................................................................................................... iii  
Executive Summary ........................................................................................................................................................ iv  
Background .................................................................................................................................................................... v  
Fundamentals of Frequency Response ........................................................................................................................ vi  
Chapter 1 : Factors Determining Rate of Change of Frequency ..................................................................................... 1  
  System Inertia .......................................................................................................................................................... 2  
  Size of Largest Credible Contingency ....................................................................................................................... 3  
  Speed of Frequency Response ................................................................................................................................. 4  
  Generator Dispatch Considerations......................................................................................................................... 5  
Chapter 2 : Fast Frequency Response Concepts ............................................................................................................. 6  
  Types of FFR Controls ................................................................................................................................................ 7  
  Illustration of System Impacts of FFR ........................................................................................................................ 8  
Chapter 3 : Concept of Critical Inertia ........................................................................................................................... 9  
Appendix A : References ........................................................................................................................................... 14
### Table of Contents

**Appendix B**: Technology-Specific FFR Capabilities
- Type 3 WTGs (General Electric) ............................................................. 15
- Type 4 WTGs (ENERCON) ................................................................. 16

**Appendix C**: Example Calculation of ROCOF ........................................... 21

**Contributors** .................................................................................................. 23
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is divided into six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.

| MRO | Midwest Reliability Organization |
| NPCC | Northeast Power Coordinating Council |
| RF | ReliabilityFirst |
| SERC | SERC Reliability Corporation |
| Texas RE | Texas Reliability Entity |
| WECC | Western Electricity Coordinating Council |
Executive Summary

As the bulk power system (BPS) continues to transition towards higher instantaneous penetrations\(^1\) of inverter-based resources, system synchronous inertia will decrease. Smaller interconnections in North America, namely the Texas and Quebec Interconnections, will be affected by this transition first given their lower level of interconnection-wide synchronous inertia, and these Interconnections are taking prudent steps\(^2\) to ensure that frequency does not reach underfrequency load shedding (UFLS) levels for large unplanned losses of generation. The high initial rate of change of frequency (ROCOF) caused by decreasing system inertia in an interconnection drives the need for faster energy injection to arrest declining frequency. This type of fast-acting response to changing frequency is considered fast frequency response (FFR), and FFR is increasingly recognized to be an essential reliability service (ERS) for reliable operation of the BPS.

This white paper provides fundamental reference materials related to lower system inertia conditions, the increasing ROCOF observed during high inverter-based resource conditions, the need for FFR in some interconnections, and the interrelationship between all factors that affect BPS frequency control. It also provides an overview of the various types of FFR based on different technologies, and it provides a framework for establishing critical inertia conditions based on current system characteristics and existing frequency response capabilities. This paper provides information related to different types of FFR that is based on industry understanding of equipment capabilities and available at the time of writing (i.e., late 2019/early 2020); equipment capabilities and operator practices are likely to continue evolving over the next decade.

This white paper outlines key system characteristics that are critical to frequency control and frequency stability that responsible entities should adopt as the penetration of inverter-based resources continues to grow. This white paper is applicable to While Balancing Authorities (BAs) are seen as the entities responsible for ensuring reliable frequency control, it also applies to Transmission Planners (TPs), Planning Coordinators (PCs), and Reliability Coordinators (RCs), and any as the entities responsible for reliable planning and operation of the interconnected BPS, are encouraged to consider the aspects described in this paper. It also applies to Generator Owners (GOs), Generator Operators (GOPs), and original equipment manufacturers (OEMS) of inverters should apply these principles for useful reference material regarding BPS reliability needs and stable frequency control. Lastly, the white paper is intended to be a useful reference for industry to better understand use of terminology regarding FFR for the industry, as well as a foundational document for IEEE P2800\(^3\) that is standardizing the performance of newly interconnecting inverter-based resources to the BPS.

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\(^1\) The term “instantaneous penetration of inverter-based resources” refers to the percentage of instantaneous load served by inverter-based resources at any given time.

\(^2\) For example, identification of critical inertia levels, maximum inverter-based resource penetration levels given specific requirements and technical capabilities, development of new requirements for FFR, considerations for provisions for ensuring frequency responsive reserve levels, additional load resource capabilities, and other tools. These are described throughout this white paper as various solutions to ensure reliable frequency control of the BPS in the face of increasing inverter-based resources.

\(^3\) https://standards.ieee.org/project/2800.html
Background

As the penetration of inverter-based resources continues to increase across the bulk power system (BPS) in North America, it is important for industry needs to be kept informed on key aspects of the changing resource mix and its impact on BPS reliability. Starting in 2012 and through ongoing studies, NERC has been evaluating one BPS essential reliability service (ERS). One such ERS is the ability to maintain system frequency during normal operation and immediately following contingency events. This is referred to as frequency control. The 2012 NERC Frequency Response Initiative Report laid a foundation for frequency control in North America, and provides much of the background information leading to this white paper. Subsequent to that report, NERC issued a Reliability Guideline on Primary Frequency Control that further elaborated on these concepts and provided clear directions on how recommendations to address possible deficiencies in primary frequency control from some generating resources. In February 2018, the Lawrence Berkeley National Laboratory (LBNL) issued a report detailing fundamental aspects of frequency control requirements for reliable operation of the BPS. This work was funded by the Federal Energy Regulatory Commission (FERC); and around this same time, FERC issued Order No. 842, revising its regulations for the provision of primary frequency response for newly interconnecting generating resources. The final rule amended the pro forma Large Generator Interconnection Agreement (LGIA) and Small Generator Interconnection Agreement (SGIA) to “require that all new generating facilities install, maintain, and operate a functioning governor or equivalent controls as a precondition of interconnection.” In particular, FERC Order No. 842 requires newly interconnecting resources to:

- Install, maintain, and operate equipment capable of providing primary frequency response capability
- Respond to frequency excursion events, when measured at the plant point of measurement (POM), with a maximum frequency fall at least outside of the ± 0.036 Hz deadband
- Adjust its output with a droop characteristic of no more than 5 percent, based on nameplate capacity
- Provide a sustained frequency response to frequency deviations rather than inject active power for a short period and then withdraw it

Defining fast frequency response (FFR) was not included in FERC Order No. 842; however, the need for FFR is growing with the increasing penetration of inverter-based resources causing faster grid dynamics. Defining FFR is a highly debated topic across the industry. At the time of writing, various FFR services have been introduced in power systems around the world that are already experiencing high instantaneous penetrations of inverter-based resources.
This white paper seeks to provide high-level guidance related to FFR, its functional use, and its interaction with other fundamental BPS frequency response aspects. Reviewing and harmonizing definitions of existing FFR market products or services is outside the scope of this paper.

This white paper outlines key system characteristics that are critical to frequency control and frequency stability that responsible entities should adopt as the penetration of inverter-based resources continues to grow. The primary focus is on the interaction between system inertia, rate of change of frequency (ROCOF), and the speed and magnitude of active power response to arrest and stabilize system frequency. Different technologies will be covered throughout the white paper, as well as fundamental aspects of ensuring sufficient energy injection within the relevant timeframes to avoid activation of underfrequency load shedding (UFLS) and recovery of system frequency to nominal values in a reasonable amount of time. Conversely, the white paper will not cover other benefits of synchronous machines beyond providing system inertia (e.g., the source of BPS short circuit current).

**Fundamentals of Frequency Response**

Balancing of generation and load to maintain system frequency within acceptable limits is an ERS for BPS reliability. Frequency control has conventionally been separated into three categories: primary, secondary, and tertiary control. Figure B.1 illustrates these categories and describes the types of controls applicable during the relevant timeframes: arresting period, recovery period, and post recovery period. Of particular interest and the sole focus for this discussion is the primary frequency control (or primary frequency response (PFR)) timeframe. Figure B.1 shows a traditional system response following a relatively large loss of generation that causes a frequency deviation. At t = 0, generation and load are balanced and system frequency is at 60 Hz (nominal). At t = 0+, an unexpected loss of generation occurs and consequently frequency begins to decrease. Energy stored in rotating masses of all machines synchronized with the grid is naturally extracted resulting in a decline of machine speed (i.e., inertial response) which manifests as a change in system frequency. After some time, power injection and withdrawal demand and generation balance, and as a result, frequency reaches its lowest point which is referred to as the frequency nadir. The timeframe leading up to the nadir is referred to as the arresting period. During this period and the subsequent recovery period, synchronous generator turbine-governors and inverter-based resource active power-frequency control systems begin responding to the deviation of system frequency by increasing active input power output. At some point, the system will return to nominal frequency in the post-recovery period due to primary frequency response combined with secondary frequency controls (i.e., automatic generation control).

---

12 The primary concern for frequency stability is typically the largest credible contingency. The concepts described in this paper use underfrequency disturbances to describe the concepts of FFR. However, these concepts also apply to overfrequency conditions as well.
Background

**frequency nadir, and initial parts of the recovery period.** Specifically, the paper will address how the shape of the system frequency response curve changes based on system inertia, speed of frequency response, and injection of energy to arrest changing frequency.

*Figure B.1: BPS Frequency Control Timeframes [Source: LBNL]*
Chapter 1: Factors Determining Rate of Change of Frequency

Rate of change of frequency (ROCOF) can be defined as “a measure of how quickly frequency changes following a sudden imbalance between generation and load.”13 ROCOF is most commonly expressed in Hertz per second (Hz/second). ROCOF is fundamentally the tangential line14 for any given point on a frequency response curve; however, this is typically estimated using two frequency measurements15 within a short period of time (i.e., 0.1–0.5 seconds).

The initial ROCOF is most commonly calculated as the change in frequency over a 0.5 second time period immediately following a sudden generation loss.16 This time period is selected since the BPS response during this time is dominated by the size of the contingency, and in a rotating machine-dominated system the system inertial response prior to the majority of turbine-governors responding to the change in perceived frequency.

\[ \text{ROCOF}_{0.5} = \frac{f_{0.5} - f_0}{0.5 \text{ sec}} \]

If the initial ROCOF is high, frequency may fall to UFLS thresholds before frequency response actions can be effectively deployed.17 Thus, initial ROCOF can be also used as a rough estimate of the amount of time before frequency reaches UFLS,18 if no responsive action is initiated. This then dictates the time in which adequate amounts of frequency response must be deployed to mitigate UFLS operation. Figure 1.1 illustrates how these parameters are calculated, which are used in subsequent discussions of the factors determining frequency response. Refer to Appendix C for further explanation. Similarly, transient stability simulation results can be used to determine the time to reach the frequency nadir, which determines the time period of the arresting phase.

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14 Which is the instantaneous derivative of the frequency.
15 Note that for inverter-based resources with no rotational components, frequency is often derived using grid measurements at the terminal of the inverter (or at the plant-level POM). Those measurements are actually mathematical calculations and filtering of grid phase and its rate of change. This white paper uses the term “measurement” rather than “calculation” for simplicity.
17 Furthermore, high ROCOF may have potential impacts on existing generator protection and operations. For example, some nuclear plants and gas turbines may trip on various turbine controls related to rapid changes or rates of change of speed (e.g., due to fuel flow or auxiliary cooling).
18 Or other relevant frequency-related protection thresholds such as generator underfrequency protection.
Chapter 1: Factors Determining Rate of Change of Frequency

Understanding the initial ROCOF following a sudden loss of generation also informs both planning and operations time horizons. System operators if any ROCOF-based protection could be triggered, whether additional generation tripping could occur, or if any distributed energy resource (DER) tripping could occur are all factors that also need to be considered. For example, high ROCOF caused approximately 350 MW of distributed energy resources (DERs) to trip on ROCOF protection in UK during a large disturbance on August 9, 2019. This document does not specifically address the impacts that DER tripping could have on BPS primary frequency response; however, the NERC System Planning Impacts of Distributed Energy Resources Working Group (SPIDERWG) is developing guidance material specifically on this subject.

Summary of Factors Affecting ROCOF

The ROCOF following a sudden imbalance between generation and load is determined by a number of factors, each of which cannot be considered in isolation without accounting for the others. Immediately following a large imbalance in generation and load, the initial ROCOF is driven by these factors:

- The size of the contingency (i.e., loss of generation or loss of imported power from dc tie lines from other interconnections)
- Overall system inertia of synchronously connected machines, including generation and motor loads
- Speed of response and magnitude of energy injection provided by generation in response to the observed deviation in frequency
- Speed of response and magnitude of load tripping or load response to the observed deviation in frequency
- The sensitivity of loads to changes in system frequency
- Incremental losses on the BPS due to changes in system flows caused by the loss of generation

While load sensitivity and incremental losses play a role in overall frequency response, the initial ROCOF is dominated by the size of the contingency event, the amount of on-line system inertia, and the speed and magnitude of frequency response (illustrated in Figure 1.2). Each of the factors mentioned above are described in the following sub-sections.

System Inertia

According to Merriam-Webster, inertia is defined as “a property of matter by which it remains at rest or in uniform motion in the same straight line unless acted upon by some external force.” Analogous to this definition, power system synchronous inertia is often defined as “the ability of a power system to oppose changes in system frequency due to resistance provided by rotating masses.” System inertia at any given time is the summation of kinetic energy stored in rotating masses of synchronously connected machines including synchronous generators, synchronous condensers, and synchronous motor loads. Synchronous generators and motors have energy stored in their rotating mass. When a sudden change in generation or load occurs, kinetic energy is inherently extracted exchanged from between the synchronous machine rotors and the electric system delivered to the system from the synchronous machines causing them to change speed (i.e., “inertial response”).

For the loss of generation, $\Delta P_{loss}$, with inertia $KE_{loss}$, initial ROCOF can be estimated as

$$\text{ROCOF} = \frac{\Delta P_{loss}}{2 \times (KE_{sys} - KE_{loss})} \times 60$$

---


21 The amount of on-line system inertia depends on the number, type, and size of generators and motor loads synchronously connected to the power system. Accounting for motor loads is challenging due to lack of data. Therefore, the contribution of motor loads to inertial response is combined with the load damping factor constant.
where $KE_{sys}$ is the total system kinetic energy from on-line synchronous generators. $KE_{sys}$ can be calculated as:

$$
KE_{sys} = \sum_{i \in I} H_i \cdot MVA_i
$$

where $I$ is the set of on-line synchronous generators, synchronous motors,\(^{22}\) and synchronous condensers; and $MVA_i$ and $H_i$ are the MVA base and inertia constant\(^{23}\) of generator or synchronous condenser $i$.

As the instantaneous penetration of non-synchronous, inverter-based generating resources (e.g., wind, solar photovoltaic (PV), and battery energy storage) continues to increase across North America, the on-line synchronous inertia will decline due to displacement of synchronous generation with nonsynchronous, inverter-based resources. The initial ROCOF after a sudden imbalance in generation and load will continue to steepen assuming all other factors are fixed.

Figure 1.3 illustrates how ROCOF increases for decreasing system inertia for a defined contingency. At some point, high ROCOF poses challenges to maintaining system frequency within acceptable limits (i.e., avoiding load shedding or cascading events) since there is insufficient time for resources (generation or load) to respond to frequency deviations. This is particularly a concern in areas where the instantaneous penetration levels of inverter-based resources, both distributed energy resources (DERs) and BPS-connected inverter-based resources, reaches significantly high levels.

Size of Largest Credible Contingency

The largest credible contingency in each interconnection is a defined contingency per NERC Reliability Standard BAL-003. Typically the largest credible contingency remains fixed unless a larger unit is installed or that largest generating unit retires.\(^{24}\) In many cases, the largest credible contingency involves a loss of a combination of generating units or large transmission tie line.

Figure 1.4 illustrates the impact that contingency size has on ROCOF at different system inertia levels. As described above, ROCOF will increase in absolute value (more negative, faster ROCOF) as system inertia declines (assuming no

\(^{22}\) Note that motor load inertia data is usually not available and, therefore, is either neglected (as a worst case assumption) or approximated.

\(^{23}\) In seconds, on each individual machine MVA base.

\(^{24}\) Note that the largest credible contingency could be the loss of an in-feed from an interconnecting tie line from another interconnection such as an HVDC circuit. The concepts described still hold for this situation as well.
other changes). However, as the size of the largest contingency relative to system load decreases, frequency performance as measured by the nadir drastically improves. In this example, the red and blue lines show systems with effective system inertia of 4.0 and 3.0, respectively, and the change in ROCOF for varying generation loss events.

As the generation mix continues to trend towards inverter-based resources, TPs, PCs, and BAs will need to consider any potential changes to the largest credible contingency. It is possible that the future grid may be dominated by many more individual generating resources that are smaller in size than the historical power system of large centralized generators.\(^{25}\) As illustrated in Figure 1.5, this will have a positive effect on initial ROCOF following the largest contingency. Conversely, due to the increase in distributed energy resources (DERs), there may be a possibility that the largest contingency is no longer a single generating unit but rather the trip of multiple DERs within the same vicinity (e.g., caused by tripping due to BPS faults) or multiple DERs over a larger area due to ROCOF or other protection settings. All these considerations will need to be studied by the BA, TP, and PC ahead of real-time operations.

**Speed of Frequency Response**

Any energy injected prior to reaching the frequency nadir will reduce the size of the frequency deviation and improve the frequency nadir. This concept drives the need for some energy injection to aid in arresting the frequency decline. An ideal frequency response shape, assuming resources could respond nearly instantaneously following a disturbance would be an "L" shaped response *(where frequency would fall to a frequency level determined by the effective droop response of the system)*. The proportional active power-frequency response, combined with the system inertia and size of the disturbance, would dictate the settling frequency. However, many types of resources\(^ {26}\) often take much longer to fully respond to changing frequency, and their turbine-governor actions continue after the frequency nadir has been reached. This is what drives the

\(^{25}\) While some forms of large synchronous generation have been retiring in the past years, other forms such as large hydroelectric generators, large combined cycle facilities, and other large wind and solar plants will likely continue to exist on the BPS in many of the North American interconnections in the foreseeable future.

\(^{26}\) This can include any resource type but is often observed in some hydroelectric generating facilities and some steam turbine generators.
rebounding\textsuperscript{27} of frequency in some interconnections.\textsuperscript{28} On the other hand, the Eastern Interconnection, due to its large system inertia,\textsuperscript{29} takes significantly longer for frequency to decline and therefore has more of an "L" shaped response since resources have much more time to arrest, respond and keep up with the declining frequency.

As the instantaneous penetration of inverter-based resources with little or no system inertia continues to increase, system ROCOF after a loss of generation will increase and the time available to deliver frequency responsive reserves will shorten. This is due to the reduction of synchronous resources that were previously providing inertia, and drives the need for faster-acting frequency responsive resources to deliver\textsuperscript{29} energy injection to the grid during a shorter arresting period. Figure 1.5 shows a typical frequency response shape and how decreasing system inertia (blue versus red plot) causes a steeper initial ROCOF, lower frequency nadir, and a frequency nadir that occurs sooner. This illustrates the importance of speed of response; however, the speed of a resource delivering FFR may be limited by its technology.\textsuperscript{30}

**Generator Dispatch Considerations**

Another factor that implicitly impacts frequency response is generator dispatch. Different unit types have different dispatch considerations\textsuperscript{31} that affect the total amount of committed generating resources to meet system demand and carry a sufficient amount of ERSs (including frequency responsive reserves). Subsequently, the amount and type of on-line generating resources have an impact on total system inertia, largest contingency size, BPS flows, frequency responsive reserve, and incremental losses.\textsuperscript{32} These factors should be accounted for when studying the potential need for FFR. For example, high inverter-based resource dispatch conditions may be assumed to be a considered "low inertia" condition. However, it is possible that during these conditions, a significant amount of on-line synchronous generation providing ERSs and scheduled to provide higher power output ready to serve load in subsequent hours will increase the system inertia at that time. On the other hand, the lowest system inertia conditions may occur on days with moderate but constant inverter-based resource penetration levels where forecast certainty is high increases and subsequently less on-line synchronous generation is needed throughout the day.

**Load Frequency Sensitivity**

Traditionally, many BAs have assumed some amount of frequency sensitivity of the load that supports frequency response (i.e., change in load consumption due to change in frequency). Further, the area control error (ACE) equation includes a bias term (beta) specifically intended to reflect the load frequency sensitivity within a BA footprint. This Demand reduction happens occurs during the arresting phase since there is no inherent delay in the response of motor loads. The frequency sensitivity value has historically been assumed to be somewhere between 1–1.5%. For example, if system demand is 50,000 MW, a 1% change in system frequency would result in a reduction of demand to 49,500 MW. However, as more directly-connected motor loads are being replaced with power electronic interfaces (e.g., variable speed drives and electronically commutated motors), frequency sensitivity of loads will likely decrease. BAs should generally understand the load composition within their footprint to determine an appropriate approximation for load frequency sensitivity, and should perform simulations with varying degrees of frequency sensitivity of loads to understand its impact to system primary frequency response.

\textsuperscript{27} Rebounding here refers to the quick recovery of frequency following the frequency nadir prior to a settled frequency being reached.
\textsuperscript{28} Such as in the Texas Interconnection and Western Interconnection.
\textsuperscript{29} Or in the case of load resources, to withdraw demand.
\textsuperscript{31} Such as start-up and shut-down times and costs, ramp rates, outage schedules, and energy certainty
\textsuperscript{32} Power flow directionality based on system dispatch has an impact on the incremental losses across the BPS. For example, historically in the Western Interconnection, the loss of the largest contingency during north-south power transfer increased the incremental losses (due to increased tie line flow) fairly substantially due to the location of frequency responsive reserves. On the other hand, if flows are south-north on these interties, then the contingency may actually reduce incremental losses and support frequency response.
Chapter 2: Fast Frequency Response Concepts

For the purposes of this paper, FFR is defined as:

**Fast Frequency Response (FFR):** energy power injected to (or absorbed from) the grid, in response to changes in measured or observed frequency, during the arresting phase of a frequency excursion event to improve the frequency nadir or initial rate-of-change of frequency.

FFR can be provided by many different forms of controls that inject additional energy power prior to the frequency nadir being reached during a frequency excursion event. Synchronous machine inertial response, a portion of traditional turbine-governor response, wind turbine generator (WTG) controls to extract additional energy power from the rotational energy of the turbine, and other fast-responding controls from batteries and solar PV all can be classified as FFR since they provide some energy replacement power to the BPS during the arresting phase.

A strong conceptual understanding of what FFR is and how it helps arrest frequency excursions is necessary to utilize FFR in future BPS operations and planning. To better describe FFR, consider the following fundamental aspects of FFR and how it supports a reliable BPS and stable frequency performance:

- Overall system frequency response should fundamentally be sustained such that sufficient amounts of energy are injected to arrest frequency excursions, maintain frequency stability, and adequately allow frequency recovery back to nominal following a sudden loss of generation or load. However, there are different types of frequency response, including both PFR and FFR, which can work in coordination to support frequency control (see Figure 2.1).

- Different technologies have the capability to provide forms of FFR in different ways, and in coordination with PFR; some forms may be sustained while other may be non-sustained. Each can help arrest frequency and improve the frequency nadir. Sustained frequency response (both FFR and PFR) refers to the ability to maintain the change in power injection until secondary frequency controls return the system to nominal frequency. However, the different forms must be studied and coordinated to ensure that there is adequate frequency responsive reserve available to arrest frequency declines and support recovery of frequency to nominal values in coordination with AGC.

- FFR can be obtained through numerous control philosophies (i.e., based on magnitude of frequency deviation, ROCOF, or other factors), that each can help during the arresting phase of a frequency excursion. These various types of controls should not necessarily be dictated unless there is a reliability need.

- Systems with large synchronous inertia that have low initial ROCOF do not have a fundamental need to distinguish between PFR and FFR. There is sufficient time for synchronous inertial response and conventional turbine-governors or other active power-frequency controls to respond to the changing system frequency without the need for additional requirements, services, or controls responding.

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33 In many cases, this is a response to locally measured frequency (or other local signal). In some cases, where speed of response is critical, other types of signals may be used to initiate FFR. For example, RAS actions triggered by specific contingencies may activate FFR.

34 This is a characteristic of frequency response in the requirements set forth in FERC Order No. 842.

35 [http://www.ercot.com/content/wcm/key_documents_lists/108744/05._RRS_Study_2017_Methodology_11022017.docx](http://www.ercot.com/content/wcm/key_documents_lists/108744/05._RRS_Study_2017_Methodology_11022017.docx)
Chapter 2: Fast Frequency Response Concepts

- **Energy Power** injected during the arresting period of a frequency excursion to reduce the initial ROCOF and improve the frequency nadir should be sufficiently fast. Thus, the term “fast” with respect to FFR is relative to each individual interconnected BPS and should not be generalized broadly.

- Fast energy-power injection provided from FFR involves relatively small changes in active power output from a generating resource. However, this control should not interfere with or degrade the stability of each interconnected resource. For this reason, in some areas such as low short circuit strength areas, faster response may not be desirable for BPS stability.

- FFR controls used in inverter-based resources should be tuned carefully to ensure reliable operation when connected to the BPS. For large voltage perturbations, FFR and PFR controls should be coordinated with other competing inverter controls particularly when the inverter is current-limited. Any control action should be based on an appropriate calculation of frequency, which often requires some time delay.

- There are currently no requirements for resources to maintain frequency responsive reserve, or “headroom”, to have the ability to respond to underfrequency events. It is the fundamental responsibility of the BA to ensure that adequate amounts of frequency responsive reserve (including sufficiently fast frequency response) are available to reliably respond to frequency excursion events and ensure UFLS is not triggered for the largest credible contingency.

- With present technology, BPS-connected inverter-based resources have the capability to provide FFR, given equipment limitations. The capability of providing FFR should be designed and configurable in all BPS-connected inverter-based resources. Actual settings for equipment installed in the field may not be set at the fastest possible values; however, these settings should be adjustable to accommodate future BPS reliability needs.

- Non-sustained FFR that is depleted prior to the post recovery period should not negatively impact frequency during the arresting or recovery periods, nor should negatively impact overall BPS frequency control.

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36 A resource providing FFR using closed-loop control with fast time constants will deliver energy to the grid based on the grid needs.
37 Some inverter-based resources may have contractual limits to the amount of power that can be delivered to the BPS. This limit may be less than the total nameplate rating of the individual generating resources. This excess capacity may be available for the purposes of providing FFR or PFR if allowed by the BA.
Types of FFR Controls
The activation of FFR can take different forms, including non-controlled response provided by synchronous generation as well as other forms of FFR that use a frequency measurement at the generating or load facility to take fast action to provide active power (or disconnect load) to the grid based on measured system frequency. These different methods include, but may not be limited to, any one or combination of the following:

1. Active power injection in proportion to measured frequency deviation (proportional response)
2. Injection of constant amount of active power once frequency reaches a pre-set trigger point (step response)
3. Active power injection in proportion to calculated ROCOF (derivative response)
4. Injection of constant amount of active power once a pre-set ROCOF is reached (step response)
5. Controlled load reduction in proportion to measured frequency deviation or ROCOF (proportional or derivative response)
6. Controlled reduction of constant amount of load on a pre-set frequency or ROCOF is reached (step response)

Each of these methods and the technologies providing FFR are described in detail in various industry reports. Figure 2.2 provides a high-level illustration of the injection of FFR from different resource types. Note that this illustration is intended to be educational and does not necessarily reflect every specific generating resource installed in the field. Some of these responses are sustained throughout the entire frequency excursion event while others are non-sustained and only provide support during the arresting phase. Studies are needed to coordinate requirements for FFR, which may include the following considerations:

- Magnitude of response
- Speed of response (i.e., response time)
- Type of control
- Sustaining time
- Availability and repeatability of response

Figure 2.2: Illustration of Frequency Response from Different Resource Types

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38 Care must be taken when using step response as a form of FFR to ensure that no stability issues are introduced (i.e., transient stability issues or subsequent overfrequency). This requires careful analysis using stability studies to ensure reliable operation. Each frequency excursion event will require a different amount of energy injection to optimally arrest the frequency and return it to nominal.

39 Triggered by relay or break operation.


41 Note that the wind-based FFR does not assume there is additional energy headroom to sustain the response (i.e., operating pre-disturbance at maximum available power). The solar response inherently is not able to provide additional energy when operating at maximum available power, and therefore assumes there is some additional energy headroom.
Figure 2.2: Illustration of Frequency Response from Different Resource Types
Illustration of System Impacts of FFR

To illustrate the impact that FFR have on the BPS, let us consider a system with increasing instantaneous penetration of inverter-based resources. Figure 2.3 shows simulations of an interconnected power system with high inverter-based resource penetration with different response times. The blue line shows the baseline system with all synchronous generators that have a relatively standard delay providing turbine-governor control of around 100 ms. This time delay is in addition to a 50 ms time delay used in the measurement of frequency. If the time delay to respond to changing frequency were delayed further to about 1 second (purple line), then the frequency nadir would deepen by about 50 mHz in this case. The initial ROCOF at the time of the disturbance would remain relatively unchanged since system inertia has not changed, and frequency settles back to the same setting point since the turbine-governor droop characteristics are also unchanged. Now consider the same system with 80% of the synchronous resources offset with inverter-based resources that all provide primary frequency response. The assumption made here is that the inverter-based resources are of the same MVA rating as the replaced synchronous machines, while also maintaining the same amount of headroom.

The simulations with this configuration, with 1 second, 500 ms, and 10 ms time delays of response are shown by the red, green, and orange lines, respectively. Note that the initial ROCOF is significantly higher since the system inertia has decreased drastically. In terms of the depth of the frequency nadir, the simulation with inverter-based resources with 500 ms delay is similar to the all-synchronous system with resources having a 100 ms delay. This is because the inverter-based resources are technically capable of responding quickly thereafter, and are not constrained by mechanical limitations that the synchronous fleet may have. Again, note that performance will degrade when inverter-based resources delay response to 1 second, causing frequency to fall much further than the all-synchronous system. This is expected since the speed of response is the same but the system inertia is much lower. Lastly, observe that the 80% inverter-based resource case with 10 ms delay provides significantly improved frequency response in terms of frequency nadir depth. While the system is acting much faster to the rapidly changing ROCOF, and the frequency nadir is reached much quicker, frequency control is simultaneously improved by the ability to provide fast energy power injection (during the arresting period). This simulation is intended as an illustrative example of how frequency stability can be improved using fast energy injection, particularly from inverter-based resources, when faced with a decreasing system inertia. However, as stated, this requires the inverter-based resources to have the capability to respond to underfrequency events and also have the frequency responsive reserve available to do so.\(^{42}\) In grids with high instantaneous penetration of inverter-based resources, these capabilities are necessary for reliable operation.

\(^{42}\) Note that in this case, the system had about 17% frequency responsive reserves available; however, only 2.8% were used following the contingency.
Figure 2.3: Example Simulation of FFR with Varying Controls and IBR Penetrations
[Source: EPRI]
Chapter 3: Concept of Critical Inertia

Critical inertia can be defined as:

**Critical Inertia:** the minimum level of system inertia necessary to ensure that frequency responsive reserves have sufficient time to be deployed and prevent the operation of the first stage of UFLS after the largest credible contingency.44

Critical inertia is broadly considered as a threshold for synchronous inertia where BPS performance requirements are no longer met given the speed of response, and the amount of FFR and PFR available to support system frequency control. As the instantaneous penetration of inverter-based resources continues to increase, the risk of reaching critical inertia levels increases. Operating close to critical inertia means that the ROCOF after a large generation contingency high, it also increases the risk of misoperation of any remedial action schemes (RASs) that rely on quick and accurate measurement of system frequency. This is because, presently, inverter-based resources operating at maximum available power are not providing FFR or PFR and are displacing synchronous generators in the unit commitment that are able to provide frequency response in the unit commitment.45

The critical inertia of a system is closely related to the initial ROCOF following the largest credible contingency. It is not a static value and is dependent on multiple factors: amount of available FFR and PFR, speed of response, size of contingency, the UFLS threshold, and other factors, described in Chapter 1. Figure 3.1 shows an example from ERCOT studies where the critical inertia can be lowered if frequency response from load resources or other types of FFR can be delivered faster.46 Similarly, the figure illustrates that if UFLS thresholds are lowered, the critical inertia value can also lowered. Lastly, although not illustrated in the figure, the critical inertia threshold also decreases if the size of the largest contingency decreases.

![Figure 3.1: Critical Inertia Based on Time of Response](Source: ERCOT)

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43 Both FFR and PFR.
44 Generally the largest credible contingency is referred to as the Resource Loss Protection Criterias in BAL-003.
45 This has been observed in ERCOT studies. ERCOT now determines critical inertia levels and monitors system inertia against these levels in real-time. Refer to the ERCOT white paper on inertia basics for more details on their implementation: [http://www.ercot.com/content/wcm/lists/144927/Inertia_Basic_Concepts_Impacts_On_ERCOT_v0.pdf](http://www.ercot.com/content/wcm/lists/144927/Inertia_Basic_Concepts_Impacts_On_ERCOT_v0.pdf).
46 In this case, the y-axis is showing the time for frequency to decline from the load resource frequency trigger to the UFLS threshold following the largest credible contingency. If it is longer than 0.5 seconds, then at inertia levels below 94 GW*s, load resources providing FFR are not able to prevent the frequency from reaching UFLS levels after the largest credible contingency. This same concept would also apply for resources providing other forms of FRR as described in Chapter 2.
BAEs, TPs, and PCs are tasked with ensuring that sufficient frequency responsive reserves are carried and delivered to the BPS to meet specific frequency response obligations. The concept of sufficiency is linked with the idea of critical inertia. Interconnected systems facing challenges with hitting crossing UFLS activation frequency thresholds levels should identify critical inertia levels and determine if mitigating actions are needed.

The critical inertia level, driven by the initial ROCOF and its impact on reaching activating UFLS, can be lowered by increasing the amount of available FFR. This is illustrated in Figure 3.2. However, the effectiveness of the additional FFR is dependent on the size of the system and how much FFR is already available. Figure 3.2 illustrates that for larger systems (blue to red to green curves), additional amounts of FFR will have varying impacts to system ROCOF. For all systems, an exponential relationship exists between ROCOF and percentage of FFR utilized (for a given contingency size). At some point, the additional FFR begins to provide less support for arresting the initial ROCOF. For example, in the illustration shown in Figure 3.2, additional FFR will provide value until a critical threshold is reached in which ROCOF cannot be held to acceptable values. For a system with very low critical inertia (e.g., Tasmania, South Australia (when islanded), and Ireland), high instantaneous penetrations of inverter-based resources will lead to large amounts of FFR being used with high ROCOF and increasing need for FFR. These concepts will all need to be closely studied and managed during real-time operations. The TPs, PCs, and BAs should be studying future system inertia levels, where appropriate, to ensure a sufficient balance between PFR, FFR, and critical inertia levels. In most cases, this will include a high inverter-based-resource penetration level with relatively low net loading.

![Figure 3.2: Relationship between FFR, Critical Inertia, and ROCOF](Source: AEMO)
Appendix A: References

NERC References


Industry References


National Laboratory References

- https://certs.lbl.gov/project/interconnection-frequency-response
Appendix B: Technology-Specific FFR Capabilities

This appendix provides technology-specific descriptions of various fast frequency response (FFR) capabilities. These sections are intended to serve as a useful reference for industry to better understand the various ways in which energy power can be quickly injected into the BPS quickly to support fast deviations of frequency.

Wind Turbine Generators

WTGs have the capability to extract additional kinetic energy stored in the rotating masses of a WTG drivetrain for a limited time in the event of an underfrequency conditions. This is true even if the WTG is operating at maximum nameplate capability. Features of the response (i.e., magnitude and duration) can be configured to meet specific grid code requirements, within the physical limitations of the machine components and controls. Typically, the response is on the order of 5-10% of additional power for several seconds, provided the machine is above a certain minimum output level at the time of the event. The over-production response, however, comes at a cost of subsequent energy recovery depending on the current wind speed.

This type of energy extractions from the rotational energy stored in the WTG was originally coined “synthetic inertia”, however this terminology has caused much confusion in the industry and the industry is collectively trying to eliminate the use of this term (including those that coined it). Rather, the most accurate term used to describe this response is “inertia-based fast frequency response”.

Figure B.1 shows the fundamental relationship between mechanical and electrical torques and is useful in visualizing which generates the additional active power injection. In steady-state, the mechanical and electrical torques must be balanced. In the event of an underfrequency event, the commanded electrical torque is greater than mechanical torque and stored inertial energy in the turbine is delivered to the grid in response to declining frequency. The contribution of FFR from each WTG within a plant will be slightly different since the controls are performed at the turbine level, and each WTG will have slightly different operating characteristics.

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47 This is similar to inertia of a synchronous machine; however, due to the power electronic interface between the WTGs and the grid, the extraction of inertial response is not inherent (as with synchronous machines) but requires fast acting controls and inject additional active power.

48 The period of over-production is typically followed by a recovery period, where the active power is below the available power for the given wind speed to allow the turbine to regain expected operating speed (to avoid turbine stall).

49 Specification for FFR are typically at the plant-level point of measurement (POM), and need to account for differences in WTG responses.
Appendix B: Technology-Specific FFR Capabilities

Type 3 WTGs (General Electric)

GE WTGs can be supplied with a “WindINERTIA” control that provides a temporary increase in active power production to contribute toward FFR. This feature can be implemented without additional hardware. A relatively large deadband of around 200 mHz is recommended for activation of this feature to mitigate the impact on mechanical loading of the turbine. Figure B.2 shows the response of a GE WTG to an underfrequency condition while operating in different modes. Note that the fastest response times come from the inertia-based FFR feature. Combining this feature with curtailed operation (to provide sustained response) offers the fastest response while also maintaining that response.50

Type 4 WTGs (ENERCON)

ENERCON WTG can be equipped with the optional “inertia emulation” to respond to a drop in grid frequency by temporarily increasing its active power output beyond the level available from the current wind conditions. The energy for this increase is drawn from the rotating masses of the WTG, such as from the annular generator, the shaft and the blades. The amount of additional power output $P_{\text{inertia}}$ provided at the time of “inertia emulation” activation $P(t=0)$ depends linearly on the deviation of the system frequency from its nominal value according to the following formula:

$$P_{\text{inertia}}(t) = \frac{f_{\text{inertia,trigger}} - f(t)}{f_{\text{inertia,trigger}} - f_{\text{inertia,min}}} P_{\text{inertia,set}}$$

where $P_{\text{inertia,set}}$ defines the maximum power increase and $f_{\text{inertia,min}}$ defines the frequency at or below which this maximum power increase $P_{\text{inertia,set}}$ is reached. Fig. B.3 shows the idealized “inertia emulation” response to an underfrequency event with $f_{\text{inertia,trigger}}$ set to 59.7 Hz and $t_{\text{inertia,max}}$ set to 10 seconds.

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50 Note that the frequency event (not shown) returns to near nominal; hence the return to pre-disturbance output.
Type 4 WTGs (Siemens Gamesa)
 Siemens Gamesa Renewable Energy (SGRE) WTGs use a feed-forward control51 (i.e., boost produced active power by a pre-determined, fixed amount) typically on the order of 6% of nameplate capability. This control occurs as soon as the frequency deviation falls outside a specified deadband. As described above, recovery after providing FFR depends on the incident wind speed, pre-disturbance operating condition, and other aspects of WTG operation. Figure B.3 shows the activation of FFR during a field test of five Type 4 WTGs each rated at 3.2 MW measured at the POI (top) and at each turbine (bottom). Plant output increases by 6% (1 MW) and the response is sustained for 9 seconds.52 This was done according to Hydro-Quebec’s technical requirements about frequency response.

Solar Photovoltaic
 Solar PV inverters do not have any rotating components and therefore do not provide inertial or inertia-based response in the same manner as synchronous resources or wind turbines. The ability to provide fast-acting energy injection to the grid is solely based on the controls programmed into the inverters or plant-level controller. There is no standardized way for providing FFR, and therefore different manufacturers have implemented different types53 of controls that can provide FFR.

Solar Photovoltaic (ABB)
 ABB solar inverters offer the possibility to implement frequency-watt characteristics either in the inverter controls or at the plant-level controller. When operating without energy storage, frequency-watt behavior is only possible for the overfrequency region (active power reduction). By using an energy storage system, this behavior can be expanded to the underfrequency region (active power increase).

Solar Photovoltaic (General Electric)
 Frequency response controls can be implemented either at the inverter level or at the plant controller level. At the inverter level, many of the GE solar PV inverters have the capability of providing fast-acting frequency response using an active power-frequency droop characteristic. The plant controller can also be used to produce a frequency response from the complete plant. In this case, frequency response in the individual inverters is disabled and the curtailment or power limit signal from the plant controller (sent to each inverter and also working on a droop curve) is used to provide frequency response. Typically, plant controller based frequency responses have not been set up to be very fast.

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51 This is in contrast to the active power-frequency control (“primary frequency response”) from the WTG, which will be a feedback control proportional to the frequency deviation that acts on a slower time scale.
52 This control includes monitoring of wind speed, power delivered, and generator speed, which dictate the ability of each WTG to provide FFR. The plant-level controller distributes FFR contributions to each WTG based on their FFR availability. Therefore, each WTG contributes a slightly different amount of FFR and has its own unique recovery characteristic.
53 Note that some inverter manufacturers have implemented controls that they have coined “inertial”; however, this white paper clarifies that these are not truly “inertial” response, and rather are a form of FFR.
Appendix B: Technology-Specific FFR Capabilities

Solar Photovoltaic (SMA)
SMA solar PV inverters can provide FFR when coupled with energy storage. The inverter reacts nearly instantaneously to a ROCOF event. The inverter “inertia response” (i.e., FFR) can be adapted to reflect different inertia (H) constants ranging from 2 seconds to 8 seconds. This control is parameterized via the speed of the nominal frequency droop characteristic. The energy storage must be sized carefully to provide the desired inertial response. SMA inverters also have active power-frequency (“frequency/watt”) functionality (referred to by SMA as “frequency/watt”), built in to the inverter functions. If the active power-frequency exceeds a defined threshold, the inverter reduces the active power feed-in. It can be selected whether the active power should be reduced by a gradient or a set power.

Solar Photovoltaic (TMEIC)
TMEIC currently has the capability to enable active power-frequency controls (also referred to by TMEIC as “frequency/watt function”) upon request, which follows UL 1741SA. For IEC versions of equipment, TMEIC also follow the BDEW German frequency response curve requirements.

Battery Energy Storage Systems
Battery energy storage systems, similar to solar PV inverters have the ability to provide FFR based on the controls programmed into the inverters. These systems have the flexibility to rapidly change the injection or consumption of active power depending on state of charge at the time.

Battery Energy Storage System (Tesla)
Tesla inverters can provide both FFR and PFR for on-grid and off-grid applications. The key distinction is that the FFR is a sub-cycle response reacting to instantaneous changes and is tunable by an “inertia constant”. On the other hand, PFR is a response to filtered frequency changes and is tunable by changing the filter time constants down to the cycles timeframe. Tesla uses the term “inertial response” when referring to FFR capability and “power-frequency droop response” when referring to active power-frequency controls. FFR response from BESS is highly tunable and also relatively quicker than a response from a thermal unit, particularly when the frequency suddenly changes direction (i.e. from under-frequency to over-frequency). Figure B.4 shows the comparison between a response from BESS and a thermal unit when the system experience frequency excursion in both directions. It is apparent that FFR provided from BESS can quickly change the direction to support frequency control.


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54 Note that UL 1741SA is a test certification standard required on most inverters being installed at both distribution- and BPS-connected facilities. However, UL 1741 has been misapplied in the past for BPS-connected facilities, using default IEEE 1547 settings for BPS plants. Refer to NERC Reliability Guideline: BPS-Connected Inverter-Based Resource Performance for more details: https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf

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Appendix B: Technology-Specific FFR Capabilities

![Figure B.4: FFR from Battery Energy Storage Compared with Thermal Unit](Source: AEMO)

**Battery Energy Storage System (Dynapower)**
In addition to UL 1741SA Frequency-watt functions, Dynapower inverters offer a function called Fcomp for FFR. Fcomp enables the battery energy storage system to autonomously respond to positive and negative frequency deviations with active power injection or absorption. Fcomp’s response characteristics are highly user configurable, allowing response magnitudes, ramp rates, and deadbands to be specifically tailored to the site. The user also sets a frequency filter to control overall function response from 1 cycle to multiple seconds.

**STATCOM with Supercapacitors (Siemens)**
SVC PLUS Frequency Stabilizer is specifically designed to provide FFR. It is an expansion of a transmission-sized STATCOM with supercapacitors. It is capable of quickly injecting active power (e.g., 50 MW in 200 ms). Supercapacitors have lower energy density; thus, the active power boost is provided only for a few seconds until PFR kicks in. The control system is configurable to react to a frequency deviation with a deadband or to a set value of ROCOF.

**Load Resources**
End-use loads can support frequency response by either tripping or reducing consumption during frequency declines. These types of loads are

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**Load Resources in ERCOT**
ERCOT utilizes load resources from over 300 sites to provide FFR. Load resources range in size from 100–250 MW, with the most common loads being industrial petrochemical plants, air separation plants, and natural gas pipeline compression sites. Load resources amount to about 4,200 MW, with around 1,400 MW of awards typically granted (up to 60% of total frequency responsive reserves). They are equipped with underfrequency relays that trip within 0.5 seconds if local frequency reaches 59.7 Hz. Starting in January 2020, ERCOT is introducing an additional new ancillary services product aimed at FFR that has a frequency trigger at 59.85 Hz and time to full response of 0.25 s.
commonly referred to as load resources. The speed of response and duration of sustaining the response for load resources depends on the type of load resource, frequency measurement time, relay and breaker operation times, and process limitations. There are two types of load resources:

- **Controllable Load Resources**: End-use loads controlled to respond by decreasing consumption of power during frequency excursion events. These loads are typically programmed with a droop characteristic or responsive to ROCOF. Commercial and industrial loads often have electronically controlled motors and processes allowing more sophisticated response than traditional breaker-switched load shedding.

- **Load Tripping**: End-use loads that trip when a specific frequency or ROCOF threshold is reached. The frequency is measured locally, and then the loads are tripped quickly to help arrest the decline.

In regions where fast response is critical (e.g., South Australia), remedial action schemes may be used to detect a contingency event (e.g., loss of interconnecting tie line or large generator loss) and trip large load resources. Although use of such SPS requires time for event detection and communication to the load resources, it still takes less time than to measure and identify a frequency or ROCOF trigger.

Many types of end-use loads have a small active power-frequency sensitivity that helps overall frequency response. This response is not relied upon to arrest frequency declines. Rather, it is represented in dynamic load models and accounted for in stability studies.

### Synchronous Generators

Synchronous generators provide inertial support to the grid immediately following a sudden imbalance in generation and load, which deters a change in grid frequency. Additionally, some synchronous generating resources have turbine-governors that respond relatively quickly, and can provide a noticeable amount of additional energy prior to frequency reaching its nadir. Figure B.54 illustrates both these concepts. A frequency excursion occurs and frequency reaches its nadir about 6.5 seconds after the loss of generation. The red plot shows the inertial response from a machine with no turbine-governor. Energy is injected to the grid as frequency falls and the resource settles back to its pre-disturbance output prior to reaching the nadir. The green plot shows the response of a machine with a fast-acting turbine-governor. This unit also experiences an inertial response as well as includes a sustained increase of power due to the turbine-governor. The energy additional power provided by both the inertial response and the fast-acting turbine governor response help support arresting the frequency decline and reducing the magnitude of the initial ROCOF.

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56 These are often large industrial or commercial loads.
Figure B.XXX5: Synchronous Inertia Response to Change in Grid Frequency
Appendix C: Example Calculation of ROCOF

This appendix provides illustrative examples of applying the ROCOF estimation technique to two different systems.

Texas Interconnection Example
Consider the frequency characteristic shown in Figure C.1. Pre-disturbance frequency at 19:47:13.15 is 60.014 Hz. Approximately 0.5 seconds after the disturbance, at 19:47:13.65, frequency has fallen to 59.98 Hz. ROCOF is calculated as

\[
ROCOF_{0.5} = \frac{f_{0.5} - f_0}{0.5 \text{ sec}} = \frac{60.014 - 59.98}{0.5} = 0.068 \text{ Hz/sec}
\]

Estimating the time to the first stage of UFLS (assumed to be 59.3 Hz in this case), one can simply extrapolate this ROCOF further

\[
f_{UFLS} = \frac{\Delta f_{UFLS}}{ROCOF_{0.5}} = \frac{60 - 59.3}{0.068} = 10.3 \text{ sec}
\]

Using this relatively crude approximation, one could assume that frequency would hit UFLS levels in 10.3 seconds for a larger event, and that resources would need to respond quicker than this timeframe providing FFR to mitigate operation of UFLS. Again, this is an approximation; more detailed engineering studies can be performed using transient simulation tools under critical inertia periods.

Figure C.1: Texas Interconnection ROCOF Estimation Example

Western Interconnection Example
Larger interconnections often have a time lag before the system begins responding to imbalance between generation and load (i.e., following a generator tripping event) due to the large system inertia resisting change in speed (frequency). Consider Figure C.2 showing a large simulated generator tripping event in the Western Interconnection. Frequency starts at nominal 60 Hz and a large generator is tripped around 2.6 seconds. Frequency begins to rapidly fall, but note the slower rolloff of frequency at the onset of the event. Within the first 0.5 seconds, frequency has not yet begun to rapidly decline. Therefore, the estimation of the ROCOF (using the solid blue line) reports a ROCOF estimation that is actually lower in magnitude than the ROCOF reaches a few seconds later (denoted by the dotted blue line). This example is simply used to illustrate that ROCOF estimation should be used with caution and is not well-suited for systems with higher inertia (for the reasons mentioned above).
Figure C.2: Western Interconnection ROCOF Estimation Example
Contributors

NERC gratefully acknowledges the contributions and assistance of the following individuals in the preparation of this report. NERC also would like to acknowledge the technical discussions and contributions of the NERC Inverter-Based Resource Performance Task Force (IRPTF).

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Agenda Item 6.b  
Planning Committee  
March 4, 2020

Inverter-Based Resources Performance Task Force Review of NERC Reliability Standards Whitepaper

Action
Approve whitepaper and authorize IRPTF to develop a SAR

Background
The IRPTF was formed in 2017 following several grid disturbances involving inverter-based resources (IBRs). In 2018, the NERC Planning and Operating Committees approved an IRPTF-developed whitepaper on identified gaps in PRC-024-2 based on IRPTF’s findings following investigations of the grid disturbances. Subsequently, a Standards Authorization Request (SAR) to modify PRC-024-2 based on the white paper was endorsed by the PC and OC and approved by the NERC Standards Committee. This led to the formation of a Standards Drafting Team (SDT) to modify PRC-024-2.

In 2019, the IRPTF undertook an effort to perform a comprehensive review of all other NERC Reliability Standards to determine if there are any potential gaps or improvements needed related to inverter-based resources. To accomplish this activity, IRPTF volunteers reviewed all of the current and future enforceable reliability standards, identified potential gaps or improvements, and presented findings to the entire IRPTF. The IRPTF reviewed these findings and finalized a set of recommendations. These findings and recommendations are documented in the subject whitepaper.

The Planning Committee and Operating Committee have reviewed the whitepaper and provided comments to the IRPTF. The IRPTF has incorporated the feedback and finalized the whitepaper.

Proposed motion language, if applicable:
“I move to approve the Inverter-Based Resources Performance Task Force (IRPTF) Review of NERC Reliability Standards Whitepaper and authorize the IRPTF to develop a SAR in accordance with the findings in the whitepaper.”

Summary
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Executive Summary
The electric industry is still experiencing unprecedented growth in the use of inverters as part of the bulk power system and that growth is possibly creating new circumstances where current standards may not be sufficiently addressing those needs. As a result, the NERC Planning Committee and Operating Committee assigned the task of evaluating today’s current standards and requirements to the Inverter-Based Performance Task Force (IRPTF). The NERC Inverter-Based Resource Performance Task Force (IRPTF) scope includes an activity to “review NERC reliability standards for potential gaps or improvements for inverter-based resources.” This white paper details the findings of the IRPTF as a result of this activity, and makes recommendations on actions that should be taken to address the issues identified.

Recommendations
The IRPTF identified potential gaps and areas for improvements in the following standards, and makes the following recommendations:

1. FAC-001-3 and FAC-002-2 should be revised to: (a) clarify which entity is responsible for determining which facility changes are materially modifying, and therefore require study, (b) clarify that a Generator Owner should notify the affected entities before making a change that is considered materially modifying, and (c) revise the term “materially modifying” so as to not cause confusion between the FAC standards and the FERC interconnection process;

2. FAC-008-3 should be revised to clarify how facility ratings are to be determined for inverter-based resources, taking into account the many components that make up an inverter-based resource, the artificial contractual or software limitations that are sometimes placed on inverter-based resources, and the scope of equipment included in the BES Definition Reference Document, Chapter I4: BES Inclusion;

3. MOD-026-1 and MOD-027-1 should either be revised or a new model verification standard should be developed for IBRs since these standards stipulate verification methods and practices which do not provide model verification for the majority of the parameters within an inverter-based resource. For example, the test currently used to comply with MOD-026-1 does not verify the model parameters associated with voltage control behavior during large disturbance conditions;

4. PRC-002-2 should be revised to require disturbance monitoring equipment in areas not currently contemplated by the existing requirements, specifically in areas with potential inverter-based resource behavior monitoring benefits;

5. Clarifications should be made to TPL-001-4 to address terminology throughout the standard that is unclear with regards to inverter-based resources the next time the standard is revised.
recommendation also applies to the draft terminology was not changed in the recently FERC-approved TPL-001-5 version of the standard; and

6.5. VAR-002-4.1 should be revised to clarify that the reporting of a status change of a voltage controlling device per Requirement R3 is not applicable for an individual generating unit of a dispersed power producing resource, similar to the exemption for Requirement R4.

The IRPTF did not identify any requirements that may need to be changed issues with the existing standard language in the BAL, CIP, COM, EOP, INT, IRO, NUC, PER, or TOP NERC Reliability Standards.

The IRPTF recommends that a SAR(s) be developed to address each of the issues identified. IRPTF recommends that this be made a priority by the NERC Standards Committee, due to the continued growth of BPS-connected inverter-based resources.

Background
The IRPTF was formed in 2017 following several grid disturbances involving inverter-based resources (IBRs). In 2018, the NERC Planning and Operating Committees approved an IRPTF-developed white paper on identified gaps in PRC-024-2 based on IRPTF’s findings following investigations of the grid disturbances. Subsequently, a Standards Authorization Request (SAR) to modify PRC-024-2 based on the white paper was endorsed by the PC and OC and approved by the NERC Standards Committee. This led to the formation of a Standards Drafting Team (SDT) to modify PRC-024-2.

In 2019, the IRPTF undertook an effort to perform a comprehensive review of all NERC Reliability Standards to determine if there are any further potential gaps or improvements, beyond what was identified for PRC-024-2, based on the work and findings of the IRPTF. To accomplish this activity, IRPTF volunteers reviewed all of the current and future enforceable reliability standards, identified potential gaps or improvements, and presented findings to the entire IRPTF. The IRPTF reviewed these findings and finalized a set of recommendations.

The IRPTF acknowledges that the findings in this whitepaper are limited by the knowledge of its members and other issues may be discovered as industry and technology continues to evolve and grow. Any such issues may be addressed through the NERC technical committee or Standards Committee processes. In particular, the IRPTF acknowledges that it did not have subject matter experts in regards to the CIP, COM, NUC, and PER standards. Nevertheless, the IRPTF performed a cursory review of these standards and did not identify any potential gaps or improvements related to IBRs.

A similar review was also conducted as part of NERC Project 2014-01 for dispersed power producing resources. However, industry knowledge of IBR technology and experience with NERC Reliability Standards

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implementation has evolved since that project was completed. For example, the Project 2014-01 efforts led to revisions of PRC-024-1, but those efforts did not capture the issues IRPTF identified in the PRC-024-2 Gaps Whitepaper.

FAC Standards Issues
The IRPTF identified issues with FAC-001-3 and FAC-002-2 that should be addressed. The IRPTF did not identify any issues with any other FAC standards.

FAC-001-3 and FAC-002-2
The purpose of FAC-001-3 is to ensure that facility interconnection requirements exist for Transmission Owners and Generator Owners when connecting new or materially modified facilities. The purpose of FAC-002-2 is to ensure studies are performed to analyze the impact of interconnecting new or materially modified facilities on the Bulk Electric System (BES). An ambiguity exists in these standards for both synchronous resources and IBRs, but it may be amplified for IBRs that are comprised of many smaller individual units connected through a network of collection feeder circuits.

Both standards imply that the term “materially modified” should be used to distinguish between facility changes that are required to be studied and those that need not be studied. However, there is not a requirement for any entity to determine what changes are to be considered materially modifying and Generator Owners are not required to notify potentially affected entities of the changes. This has led to confusion and potential reliability issues within industry. For example, a Transmission Planner may consider an IBR control system software change to be materially modifying, but if the Generator Owner does not consider such a change to be materially modifying they will not notify the Transmission Planner of the change.

Additionally, this ambiguity exists for both synchronous resources and IBRs, but it may be amplified for IBRs that are comprised of many smaller individual units connected through a network of collection feeder circuits. The frequency of change of components could be higher for IBRs, and the magnitude of such changes could vary. For example, due to a rapid change in wind turbine generator (WTG) technology, it is a common practice to re-power an existing wind power plant with bigger blades while keeping the same electrical generator and converter systems (for both Type 3 and Type 4 WTGs). This may be considered a material modification since a new set of bigger blades (e.g., 93 m to 208 m) can produce more power at a lower wind speed. However, the nameplate rating of the plant will remain unchanged. From an interconnection requirements’ perspective, it is the electrical generator and converter system that impacts the majority of the steady-state, short-circuit, and dynamic characteristics and therefore will be mostly unchanged. Therefore, the question remains if these sort of repowering projects should be studied under FAC-002-2 R1 and which entity should make that determination. Therefore, the IRPTF recommends these standards be modified to specify which entity is responsible for determining what facility changes should be considered materially modifying and requiring that Generator Owners notify the appropriate affected entities before they make such a change.

The IRPTF further notes that if the plant owner makes a change in electrical generator, power electronic converter, or any control systems (including change of OEMs for partial individual units), it should be
considered as “materially modifying”. On the other hand, due to the advanced nature of control systems in the power electronic converters, it is not uncommon to have firmware updates (similar to the updates on a personal computer) occasionally that may have no impact on the functionalities of the WTGs or plant-level controls in any way. Therefore, such firmware updates that do not affect the electrical performance of the plant should not be considered as “materially modifying”.

Additionally, in FERC-jurisdictional areas, the term “Materially Modifying Modification” refers to a new generation project’s impact on other generators in the interconnection queue. This has led to widespread confusion across the industry regarding the correct application of these terms related to the FERC Open Access Transmission Tariff (OATT) implementation and the NERC Reliability Standards requirements. The application of these terms is different between the FERC process and the NERC Reliability Standards (specifically FAC-001-3 and FAC-002-2). For example, if a Generator Owner changes out the inverters on an existing solar PV resource, the change may have no impact on other generators in the interconnection queue, and thus would not be considered a Material Modification under the FERC OATT rules. But such a change could have reliability impacts on the system that should be studied in accordance with FAC-002-2. Any revision to these standards should consider changing the term to avoid this confusion. FAC-001-3 and FAC-002-2 should be modified to clarify the use of “materially modifying”, particularly as it relates to compliance with the standards.

**FAC-008-3**

The purpose of FAC-008-3 is to ensure that facility ratings used in the reliable planning and operation of the BES are determined based on technically sound principles. A Facility Rating is essential for the determination of System Operating Limits (SOLs).

FAC-008-3 changes are needed to clarify the standard when it comes to facility ratings for IBRs. In the existing FAC-008-3, it states that the rating shall include the low-side of the GSU transformer if the Generator Owner does not own the GSU and the high-side of GSU if the Generator Owner does own the GSU. It is clear that such a requirement is geared towards a synchronous generator that is connected to the BES only through a GSU. However, with IBRs, there are many components between the individual inverters or turbines and the main power transformer (MPT) that interconnects the plant with the BES. Such components include IBR transformers (e.g., stepping up voltage from 690V or 450V to a collector system voltage of 34.5 kV), multiple collection feeders, and one or more MPTs based on the plant design. Therefore, the existing language within Requirement R1.1 does not apply to IBRs and additional language needs to be incorporated to clarify how the facility ratings of IBRs need to be calculated.

Additionally, the rating of a wind or solar plant is sometimes based on an artificial limit in the Power Purchase Agreement (PPA) and not the sum of the nameplate ratings of the individual wind turbines, inverters, or solar panels. Furthermore, this limit can be imposed by the plant controller or “hard coded” in the inverters. Therefore, clarification must be provided in a revised FAC-008-3 standard to have these identified issues taken care of.
MOD Standards Issues

The IRPTF identified issues with MOD-026-1 and MOD-027-1 that should be addressed. The IRPTF did not identify any issues with any other MOD standards that are not already being addressed in other forums.

MOD-026-1 and MOD-027-1

MOD-026-1 and MOD-027-1 require, among other things, GOs to provide verified dynamic models to their Transmission Planner (TP) for the purposes of power system planning studies. Both standards contain language that is specific to synchronous generators and is not applicable to IBRs. For example, subrequirement 2.1.3 in MOD-026-1 states that each verification shall include “model structure and data including, but not limited to reactance, time constants, saturation factors, total rotational inertia...” The standards should be revised to clarify the applicable requirements for synchronous generators and IBRs. For example, total rotational inertia should not be required for IBRs, while voltage ride-through control settings should only be required of IBRs and not synchronous generators.

To some degree, all dynamic model parameters affect the response of a represented resource in dynamic simulations performed by power engineers. Accurate model response is required for the engineers to adequately study system conditions. Hence, it is crucial that all parameters in a model be verified in some way. Additionally, however, a significant number of parameters in the models are not verified in the typical verification tests prescribed used to comply with MOD-026-1 and MOD-027-1. For example, the test currently used to comply with MOD-026-1 does not verify the model parameters associated with voltage control behavior during large disturbance conditions.

This issue is one of the predominant reasons why ride-through operation modes such as momentary cessation were able to persist and promulgate in IBRs without the knowledge of planners and system operators until the Blue Cut Fire and Canyon 2 Fire events exposed them. The dynamic models did not accurately represent this large disturbance behavior due to the model deficiency and because certain key parameters that govern large disturbance response were incorrectly parameterized. However, many of the same plants that entered momentary cessation mode during these events were able to provide verification reports that demonstrated that the small disturbance behavior driven mainly by plant-level control settings reasonably matched modeled performance in compliance with these standards.

This reliability gap exists for both synchronous generators and IBRs. However, it is potentially more severe for IBRs since their behavior is based more on programmable control functions than for synchronous generators which have behavior that is based more on the physical characteristics of the machine. Both MOD-026-1 and MOD-027-1 should be reviewed and potentially revised to provide sufficient clarification for verification of generating resource model parameters, or a new standard should be developed to meet the reliability objective. Additionally, the IRPTF notes that it is not feasible to stage large disturbances for verification purposes, so other methods for verification of model performance under large disturbance conditions may need to be developed.

PRC Standards Issues

The IRPTF identified issues with PRC-002-2 that should be addressed. The IRPTF did not identify any issues with any other PRC standards that are not already being addressed in other forums.
The purpose of the NERC standard PRC-002-2 is to have adequate data available to facilitate analysis of BES disturbances. Requirements R1 and R5 provide guidance on selecting BES elements where data monitoring is required, which is summarized briefly below.

1. Per Requirement R1 (which uses criteria outlined in Attachment 1), Sequence of Event Recording (SER) and Fault Recording (FR) devices are required at BES buses with high short circuit MVA values. The methodology identifies the top 20 percent of BES buses with highest short circuit MVA values and requires a subset of these buses to be monitored for SER and FR data.

2. Requirement R5, identifies BES locations based on a size criteria for generating resources and other critical elements such as HVDC, IROLs and elements of UVLS program, for which Dynamic Disturbance Recording (DDR) data is required. In regard to generation resources, it includes requirements for monitoring at sites with either gross individual nameplate rating of greater than or equal to 500 MVA or gross individual nameplate rating greater than or equal to 300 MVA where gross plant/facility aggregate nameplate rating is greater than or equal to 1000 MVA.

Requirements R1 and R5 are written with a focus on synchronous machine dominated systems. The BES elements with short circuit MVA in the top 20% are typically elements at baseload generating plants with multiple generating units or BES elements within a heavily meshed transmission network usually close to large load centers. IBRs do not contribute much fault current and are usually interconnected in remote parts of the system. As such, the short circuit MVA for the point of interconnection (POI) bus and nearby BES buses is not expected to be in the top 20%. Hence, BES buses near these resources are more likely to be omitted from requiring SER and FR data monitoring. In addition, most IBRs do not meet the nameplate rating criteria outlined in Requirement R5. With increasing penetration of IBRs, it is important that some of these resources and nearby BES elements are monitored with DDR and SER/FR devices, respectively.

Recent disturbance analyses of events involving IBRs including the Blue Cut Fire and Canyon 2 Fire have demonstrated the lack of disturbance monitoring data available from these facilities and nearby BES buses to adequately determine the causes and effects of their behavior. None of the IBRs involved in these two events met the size criteria stated in PRC-002-2 to be required to have disturbance monitoring. Additionally, none of the buses near the IBRs met the criteria in Requirement R1 for being required to have SER and FR devices since the IBRs inherently produce very little fault current. This led to difficulty in adequately assessing the events.

Furthermore, the type of data that needs to be collected must be point-on-wave quality — even 60 samples per second is too slow to capture the needed detail of what the IBR was exposed to during the disturbance. For example, all events analyzed by the IRPTF have indicated that the transient AC overvoltage tripping occurring at the inverter level is not identified at the Point of Interconnection (POI). Without in-plant data capturing some of the inverter terminal conditions, the engineer is not able to deduce why the transient AC overvoltage is occurring at the inverters while the POI is experiencing low voltage during on-fault conditions. Thus, having inverter SER data, time stamped to 1 ms accuracy, is critical for identifying the root cause analysis of why inverters tripped for BPS faults.
With the changing resource mix and increasing penetration of IBRs, PRC-002-2 does not serve its intended purpose adequately. To the extent that the standard is already requiring monitoring devices, the location requirements need to be revised. These revisions are necessary so that required data is available for the purposes of post-mortem event analysis and identifying root causes of large system disturbances.

**TPL Standards Issues**

The IRPTF did not identify any requirements that may need to be changed in TPL-007-3, Transmission System Performance for Geomagnetic Disturbance Events, or the upcoming revisions to the standard. The IRPTF did identify several clarifications that may be helpful in the requirements of TPL-001-4, Transmission System Planning Performance Requirements. However, these clarifications are minor in nature and do not warrant changing the standard at this time. These clarifications should be considered by a subsequent SDT if the standard is revised in the future.

**TPL-001-4**

TPL-001-4 requires Planning Coordinators (PCs) and TPs to assess the reliability of their portion of the BES for various conditions across several specified future years and to plan Corrective Action Plans to address identified performance deficiencies. The requirements and sub-requirements include, among other things, certain simulation assumptions to be used by the planner and performance requirements.

Sub-requirements 3.3 and 4.3 describe simulation assumptions that the planner should use when performing contingency analysis for the steady-state and stability portion of the assessment, respectively. Sub-requirements 3.3.1.1 and 4.3.1.2 each require the planner to include the impact of the “tripping of generators where simulations show generator bus voltages or high side of the [GSU] voltages are less than known or assumed generator low voltage ride-through capability.”

The term GSU transformer can be confusing to GOs of IBR facilities because they will often refer to the transformer that steps the voltage up from the individual inverter (e.g., 600 V) to the collector system voltage (e.g., 34.5 kV). In this case, there is usually another transformer (i.e., the MPT) to step the voltage up from the collector system voltage to transmission system voltage. It was likely the intent of the TPL-001-2 SDT to be referring to transmission system voltages when drafting the language that refers to known or assumed generator low voltage ride-through capability at the high-side of the GSU. Therefore, the language in these sub-requirements should be modified to provide clarity for inverter-based resources.

Sub-requirements 4.1.1 and 4.1.2 provide stability performance criteria when a generator “pulls out of synchronism” in system simulations. Although an inverter-based resource does synchronize with the grid, the phrase “pulls out of synchronism” is typically applicable only to synchronous generators, referring to when a synchronous machine has an angular separation from the rest of the grid. Therefore, these sub-requirements could be clarified by clearly stating that this performance criteria is for synchronous generators.
Sub-requirement 4.3.2 specifies that stability studies must “simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area.” It then contains a list of example devices that have dynamic behavior. Not included in this list are power plant controllers and inverter controls, which often dominate the dynamic response of IBRs. While the sub-requirement does not preclude the simulation of plant-level controllers and inverter controls, it would add clarity if they were added to the list.

The suggested clarifications for sub-requirements 3.3, 4.3, 4.1.1, 4.1.2, and 4.3.2 should be considered by a future SDT when editing the standard. However, the IRPTF does not believe the clarifications by themselves warrant changing the standard at this time. It should be noted that the identified issues with TPL-001-4 also apply to the draft TPL-001-5 standard that is awaiting FERC approval as of the publication of this whitepaper.

**VAR Standards Issues**

The IRPTF identified issues with VAR-002-4.1 that should be addressed. The IRPTF did not identify any issues with any other VAR standards.

**VAR-002-4.1**

The purpose of VAR-002-4.1 is “to ensure generators provide reactive support and voltage control, within generating Facility capabilities, in order to protect equipment and maintain reliable operation of the Interconnection.” Requirement R3 requires each Generator Operator (GOP) to notify its Transmission Operator (TOP) of a status change on “the AVR, power system stabilizer, or alternative voltage controlling device within 30 minutes of the change.” Requirement R4 is similar in that it requires each GOP to notify its TOP of “a change in reactive capability due to factors other than a status change described in Requirement R3.”

For dispersed power producing resources, it is not clear if a GOP is required to notify the TOP for the status change of voltage control on an individual generating unit. For example, if an IBR consisting of one hundred inverters has one inverter trip out of service, is the GOP required to notify the TOP per Requirement R3? NERC Project 2014-01 revised VAR-002 Requirement R4 to clarify that it is not applicable to individual generating units of dispersed power producing resources. The IRPTF did not identify any reason why Requirement R3 should be treated differently than Requirement R4 in this respect and recommends VAR-002-4.1 be modified to make this same clarification to Requirement R3.
Conclusion and Recommendation

The IRPTF performed a comprehensive review of NERC Reliability Standards to determine if there were potential gaps for improvements based on the work and findings of the IRPTF. The outcome of this analysis includes the following recommendations:

2.1. FAC-001-3 and FAC-002-2 should be revised to address the issues described herein;

4. FAC-008-3 should be revised to address the issues described herein;

5.2. MOD-026-1 and MOD-027-1 should either be revised to address the issues described herein or a new model verification standard should be developed for IBRs.

6.3. PRC-002-2 should be revised to address the issues described herein;

7.4. Clarifications should be made to TPL-001-4 to address the issues described herein the next time the standard is revised. This recommendation also applies to the draft TPL-001-5; and

8.5. VAR-002-4.1 should be revised to address the issues described herein.

The IRPTF recommends that a SAR(s) be developed to address each of the issues identified. IRPTF recommends that this be made a priority by the NERC Standards Committee, due to the continued growth of BPS-connected inverter-based resources.
White Paper and SAR for PRC-019-2 - Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

Action
Approve the attached white paper developed by the System Protection and Control Subcommittee (SPCS) and endorse the associated Standards Authorization Request (SAR), also attached.

Background
Reliability Standard PRC-019-2 addresses the reliability issue of miscoordination between generator capability, control systems, and protection functions. However, this standard was developed with a bias toward synchronous generation and does not sufficiently outline the requirements for all generation resource types.

The purpose statement of the standard requires modification to be inclusive of all generation resource types. Additional clarity is needed in specifying the aspects of Dispersed Power Resources that should be coordinated. There are also issues within PRC-019-2 regarding synchronous generation that need to be corrected or clarified to remove ambiguity.

The draft SAR and white paper were reviewed by PC members following the March 2019 PC meeting and presented to the PC in June 2019. The PC conducted an email ballot from July 24 – August 2, 2019, on a modified version of the white paper and SAR. The modified version that the PC voted on did not include provisions for addressing momentary cessation of inverter-based resources in scope for the proposed revisions to PRC-019. The results of the vote were approval of the white paper and endorsement of the SAR. At the September 2019 PC meeting, PC members were informed that the SPCS had concerns with the removal of the provisions for momentary cessation and would review the white paper and SAR. The attached white paper and SAR have been revised to include provisions for addressing momentary cessation of inverter-based resources in scope for the proposed revisions to PRC-019. SPCS leaders will discuss the reliability needs addressed in this SAR during the PC meeting.

Proposed motion language, if applicable:

- “I move to approve the white paper on Reliability Gaps in Reliability Standard PRC-019-2”
- “I move to endorse the SAR for PRC-019 SAR as presented”

Summary
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NERC PRC-019 SAR
White Paper
March 2019

Background
It is clear to the industry that PRC-019-001 was initially developed to address traditional synchronous generation. The requirements and language are purely based on synchronous generator philosophies described in IEEE C37.102 Guide for AC Generation Protection. This creates a conflict within the standard since inverter based resources and non-rotating resources are designed and operated in a completely different manner than synchronous generation. The language and requirements within the standard do not align in a clear manner to all generation resource types. In addition, there have been questions within the industry as to the applicability of requirements for synchronous condensers. These conflicts are forcing entities and manufacturers to make interpretations and assumptions for requirements within the standards.

The bulk power system (BPS) in North America continues to experience a change in generating resources used to provide reliable power. There is a paradigm shift in generation resource mix, with an increased penetration of inverter-based and non-rotating resources to replace the retirement of synchronous generation. These new resource types must provide the same reliability as traditional synchronous generation to prevent system instability.

PRC-019 Reliability Needs
There is a need for additional and/or enhanced reliability requirements to address the changing resource mix that have a material effect on the reliability of the Bulk Electric System (BES). Several items pertinent to the intent of PRC-019 are in need of updating, clarifying, or augmenting to ensure the ongoing reliable coordination of generation plant capabilities, controls, and protection. Below are the conflicts and ambiguities identified within the standard.

Clarification of Applicable Facilities
- Section 4.2.1 should be clarified that it pertains specifically to synchronous generating units to create clear differentiation from other facilities.
- Section 4.2.3 should be clarified that it pertains specifically to synchronous generating units to create clear differentiation from other facilities.
- Section 4.2.3.1 should be clarified so that it pertains to IBRs regardless of the type of control that is used (i.e., individual resource controller or plant/facility). This section indicates that the individual generating units identified through Inclusion I4 of the Bulk Electric System (BES) definition are

1 Park controllers (i.e., plant/facility controllers) send set points to the individual generators to maintain the voltage level at the point of interconnection (POI).
included only if voltage control for the facility is performed solely at the individual generator; thus, seems to exclude the individual IBRs from the standard if a plant/facility level or park controller is used for voltage control. In addition, Inclusion I4 Figure I4-1, I4-2, I4-3, and I4-4 should be revised to provide end users with an accurate depiction of these facility types.

- Determine whether static or dynamic reactive resources (i.e., capacitor banks, static VAR compensators, STATCOMs etc.) and synchronous condensers should be applicable to all types of generation resources. The language in footnote 1 for Requirement R1 implies that reactive compensating devices are not applicable since they are not installed or activated on a generator. These devices are system level voltage regulators and have no effect on an individual inverter capability or limiter functions within an inverter control system; however, they are important to system VAR support and reliability. For example, Type 1 and Type 2 wind turbine generators (WTG) typically employ reactive compensating devices on the collector side of the generator step-up (GSU) transformer. In this case, reactive compensating devices are integral to supporting the systems reactive needs and enhances the reliability of the BES. These devices are not captured by the BES definition because they typically connect at voltages less than 100 kV; however, they should be applicable to the standard asynchronous and non-rotating resources.

Requirements within the Standard

The language is not clear for all generation resource types with respect to coordinating the voltage regulating system controls, (including in-service limiters and protection functions) with the applicable equipment capabilities and protection system devices/functions. The requirements must be revised by amending or creating Requirement(s) to address all types of generation resources (i.e. IBR).

Control Systems

The standard is currently biased toward automatic voltage regulating (AVR) control systems used in conjunction with traditional synchronous generation. However, the standard should address control systems associated with all types of generation resources that are essential to reliability. Typically, inverters have a control system and the facility has a plant controller with a separate control system. The inverter has a control system that may operate in VAR control, Power Factor control, reactive power priority, or active power priority. The plant controller has a control system that may operate in Power Factor or Voltage Control mode. Coordination between any plant/park controller with individual resource control systems must be achieved to prevent unnecessary reduction of the resource or grid instability.

- Momentary cessation – “momentary cessation” is a function within an Inverter Based Resource (IBR) control system that reduces active and reactive current to zero when voltage is outside of a defined band drops below a given threshold. A reduction in active and/or reactive current can negatively impact reliability, especially during system perturbations, since the function prohibits the IBR from providing support to the BPS during these events.

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2 “Limiters or protection functions that are installed and activated on the generator or synchronous condenser.”
3 The voltage settings that cause momentary cessation are considered voltage protection settings within the inverter. Other functions within the inverter can cause momentary cessation to operate in a manner similar to a protective function. However, the focus for PRC-019 is on voltage-related functions.
4 Including dynamic active power-frequency control and reactive power-voltage control.
standard will ensure that BES generators are not unnecessarily ceasing current injection during abnormal conditions, that any cessation of current is coordinated with equipment capability, and that these functions do not pose a risk to BPS reliability. Revisions to the standard should consider methods or parameters to eliminate momentary cessation where possible, otherwise ensure it is coordinated with equipment capabilities of the inverter where it cannot be eliminated (for legacy equipment).

- "momentary cessation" is a function within an IBR control system that reduces active and reactive current to zero when voltage drops below a given threshold. A reduction in active and/or reactive current can negatively impact reliability, especially during system perturbations. Momentary cessation operates in the same manner as a protection system by removing generation from the grid at a given threshold. This standard ensures generating units are not unnecessarily removed from service when abnormal conditions do not pose a risk.

- Momentary cessation typically consists of an under/over voltage operating quantity with no time delay. This function essentially operates as an instantaneous under/over voltage protection element. The intent of PRC-019 this standard is to coordinate voltage protection functions with equipment capabilities, and it is important for IBRs to coordinate use of momentary cessation as a part of these coordination activities. Therefore, momentary cessation should adhere to the coordination requirements of the PRC-019 standard.

Momentary cessation of generating resources can have an adverse effect on system reliability as experienced during the Blue Cut Wild Fire in California. Modifications to PRC-019 The standard should clearly state that momentary cessation should be coordinated with the equipment capabilities of the inverter. More specifically, if the inverter can eliminate the use of momentary cessation it should do so; if momentary cessation cannot be eliminated, it should be set near the equipment capabilities of the inverter. The figure below illustrates an example of coordinating momentary cessation with equipment capability using voltage. Note that there may be a time-based component to the use of momentary cessation (e.g., the inverter may be able to provide current for some time above a voltage level), and these should be considered as well (particularly in relation to PRC-024).

Specifically for the scope of PRC-019, this should entail coordinating momentary cessation with any applicable voltage thresholds. Reduce or eliminate the condition known as momentary cessation. The recommendations described above will ensure alignment between PRC-019 and PRC-024 should be aligned with regards to momentary cessation in that momentary cessation should not be used, to the extent possible, to ensure BPS reliability.

When operating in voltage control mode, a modern control system designed for IBR controls the inverter’s reactive power output in a similar fashion as an excitation system regulates the reactive power

---

1 Momentary cessation has been observed in BPS solar PV facilities in all disturbances analyzed by NERC, including but not limited to the Blue Cut Fire, Canyon 2 Fire, Palmdale Roost, and Angeles Forest disturbances.
2 Momentary cessation is commonly triggered in inverter control systems using a voltage magnitude threshold for high and low voltage. High voltage is generally to protect the IGBTs within the power electronics and low voltage is generally to avoid injecting current when voltage phase is not measured accurately (e.g., distorted during faults).
3 See NERC IRPTF BPS-Connected Inverter Based Resource Performance
output of a synchronous generator. It controls the inverter’s reactive power output based on system voltage change. It also has a limiter function/equipment capability limiting the maximum reactive power output to prevent overloading the inverter when it operates in voltage control mode. If the momentary cessation is a built-in function of the IBR control system and cannot be turned off, the settings of momentary cessation shall coordinate with the setting of the limiter/equipment capability for complying with PRC-019.

**Active/Reactive Power for US2200**

**Notes**
- SmartGen inverters can operate in either: power factor priority mode or reactive power (Q)-priority mode
- In power factor priority mode, inverter will maintain power factor constant and vary reactive power depending on active power from the photovoltaic array cycle the VSC rating of the inverter
- In reactive power priority mode, inverter will maintain Q constant and will limit active power (P) depending on the VSC rating of the inverter
- If active power output of the inverter is dependent on grid voltage and will be reduced with grid voltages under 3 pu
- For grid voltages 1 pu and greater, inverter is power limited to its nameplate rating

![Active Power (P) and Reactive Power (Q) depending on VAC @35°C](image-url)
Steady State Stability Limit
The manual SSSL theory is only applicable when a generator AVR is in manual operation mode; however, the standard specifically instructs an entity to assume the AVR is in automatic mode. This assumption is identified because it is industry standard to coordinate the UEL with the SSSL since that is the most conservative approach for AVR operation. However, the protection settings typically coordinate with the machine capabilities and not the manual SSSL.

Synchronous Condensers
A synchronous condenser operates in a manner similar to a traditional synchronous generator in terms of voltage regulation and the associated excitation control system. In addition, the electrical quantities for a synchronous condenser match the quantities specified in the manual SSSL methodology. However, the machine does not have a prime mover and thus cannot output real power. This drastically reduces the machines operating region since the unit will only be able to absorb or generate reactive power. The standard should clearly specify if a synchronous condenser should be treated in the same manner as a traditional synchronous generator.

Stability Limits for Other Types of Generation Resources
Current references and methods in the standard regarding stability limits are all based on synchronous machines (AVR in manual mode, fixed excitation voltage, etc.). The standard should clearly specify if stability consideration is necessary for all types of generation resources. If so, the standard should provide stability methodology/guidance for all types of generation resources.

**Voltage Drop Across Resource Collector Systems**
The standard should identify whether the voltage drop across the collector system, bus, generator step-up (GSU) transformer, or other facilities must be considered for coordination.

**Time Frame to Perform Coordination**
The current language in Requirement R2 can be interpreted as allowing the coordination to be performed 90 days AFTER the “implementation of systems, equipment, or setting changes.” This would allow an entity to put a unit back into service without performing coordination; thus, jeopardizing reliability and short circuiting the standard. The original SDT has confirmed that the 90-day time frame was for scenarios in which an entity discovered miscoordination and that coordination should occur before new/revised systems are placed into service.
The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

**Requested information**

<table>
<thead>
<tr>
<th>SAR Title:</th>
<th>Revisions to Address Dispersed Power Resource (DPR) (PRC-019-2)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Date Submitted:</td>
<td>10/26/2019</td>
</tr>
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</table>

**SAR Requester**

<table>
<thead>
<tr>
<th>Name:</th>
<th>Chair Jeffrey Iler &amp; Vice Chair Bill Crossland on behalf of the</th>
</tr>
</thead>
<tbody>
<tr>
<td>Organization:</td>
<td>NERC System Protection and Control Subcommittee (SPCS)</td>
</tr>
</tbody>
</table>
| Telephone: | Chair: (614) 933-2373  
Vice Chair: (216) 503-0613 |
| Email: | Chair: jwiler@aep.com  
Vice Chair: bill.crossland@rfirst.org |

**SAR Type (Check as many as apply)**

- [ ] New Standard
- [x] Revision to Existing Standard
- [ ] Add, Modify or Retire a Glossary Term
- [ ] Withdraw/retire an Existing Standard
- [ ] Imminent Action/ Confidential Issue (SPM Section 10)
- [ ] Variance development or revision
- [ ] Other (Please specify)

**Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)**

- [x] Regulatory Initiation
- [x] Emerging Risk (Reliability Issues Steering Committee) Identified
- [ ] Reliability Standard Development Plan
- [x] NERC Standing Committee Identified
- [ ] Enhanced Periodic Review Initiated
- [x] Industry Stakeholder Identified

**Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?)**:

Reliability Standard PRC-019-2 addresses the reliability issue of miscoordination between generator capability, control systems, and protection functions. However, this standard was developed with a bias toward synchronous generation and does not sufficiently outline the requirements for all generation resource types.

The purpose statement of the standard requires modification to be inclusive of all generation resource types. While this class of resources are currently included in the applicability of PRC-019-2, additional clarity is needed in specifying the aspects of DPRs that should be coordinated. There are also issues within PRC-019-2 regarding synchronous generation that need to be corrected or clarified to remove ambiguity. These comprehensive updates align with the intent and spirit of the standard.
Requested information

<table>
<thead>
<tr>
<th>Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):</th>
</tr>
</thead>
<tbody>
<tr>
<td>This project will enhance reliability by maximizing a generator's capability and its ability to support grid stability during system disturbances by requiring the coordination of control systems with equipment capabilities and protection functions of all generation resource types.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Project Scope (Define the parameters of the proposed project):</th>
</tr>
</thead>
<tbody>
<tr>
<td>The SDT should develop language that is relevant to all generation resource types. This will include modifications to the purpose statement, the applicability and requirements. Additionally, the SDT should consider modifying Inclusion I4 of the Bulk Electric System (BES) definition and the associated diagrams in the BES Reference Document.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (e.g. research paper) to guide development of the Standard or definition):</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Applicable Facilities – Clarification of applicable facilities.</td>
</tr>
<tr>
<td>a. Clarify Section 4.2.3.1 to state that it pertains to both the individual resources and the plant level voltage controls. [This section indicates that the individual generating units identified through Inclusion I4 of the Bulk Electric System (BES) definition are included only if voltage control for the facility is performed solely at the individual generator; thus, it is ambiguous as to whether this excludes the individual resources from the standard when the plant/facility level or park controller is being used for voltage control.]</td>
</tr>
<tr>
<td>b. Verify that static or dynamic reactive compensating devices (i.e., capacitor banks, static VAR compensators, STATCOMs, etc.) and synchronous condensers within BES generating facilities should be subject to the standard since they must be coordinated for protection and plant capability. [The language in footnote 1 for Requirement R1 implies that reactive compensating devices are not applicable since they are not installed or activated on a generator. These devices are system level voltage regulators and have no effect on an individual inverter capability or limiter functions within an inverter control system; however, they are important to system VAR support and reliability. For example, Type 1 and Type 2 wind turbine generators (WTG) typically employ reactive compensating devices on the collector side of the generator step-up (GSU) transformer. In this case, reactive compensating devices are integral to supporting the system reactive needs and enhances the reliability of the BES. These devices are not captured by the BES definition because they typically connect at voltages less than 100 kV; however, they should be applicable to the standard for asynchronous and non-rotating resources.]</td>
</tr>
</tbody>
</table>

---

1. The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.
2. Reference Section 4.10.10 of the White Paper from Project 2014-01 Standards Applicability for Dispersed Generation Resources
3. “Limiters or protection functions that are installed and activated on the generator or synchronous condenser.”
Requested information

c. Revise Inclusion I4 of the BES definition and Figures I4-1, I4-2, I4-3, and I4-4 in the BES Reference Document to accurately depict all generation resources.

2. Requirement(s) – Ensure the language is clear and inclusive of all generation resource types with respect to coordinating control systems, protection functions, and equipment capabilities.

   a. Controllers specific to DPR – The standard is currently biased toward automatic voltage regulating (AVR) control systems used in conjunction with synchronous generation. The standard should address other control systems associated with DPRs that are essential to reliability. Typically, inverters have a control system and the facility has a plant controller with a separate control system. The inverter has a control system that may operate in VAR control, Power Factor control, reactive power priority, or active power priority. The plant controller has a control system that may operate in Power Factor or Voltage Control modes. Coordination between any plant/park controller with individual resource control systems must be achieved to prevent unnecessary reduction of the resource.

   b. Momentary cessation – “momentary cessation” is a function within an Inverter Based Resource (IBR) control system that reduces active and reactive current to zero when voltage drops is outside of a defined band below a given threshold. A reduction in active and/or reactive current can negatively impact reliability, especially during system perturbations, since Momentary cessation operates in the same manner as a protection system the function prohibits the IBR from providing support to the BPS during these events, removing generation from the grid at a given threshold. Ensuring clear language in this standard will ensure that BES generating units are not unnecessarily ceasing current injection removed from service when during abnormal conditions, that any cessation of current is coordinated with equipment capability, and that these functions do not pose a risk to BPS reliability.

   —Momentary cessation typically consists of an under/over voltage operating quantity with no time delay. This function essentially operates as an instantaneous under/over voltage protection element. The intent of this standard is to coordinate voltage protection functions with equipment capabilities. Therefore, momentary cessation should adhere to the coordination requirements of the PRC-019 standard.

   —Momentary cessation of generating resources can have an adverse effect on system reliability as experienced during the Blue Cut Wild Fire in California. Revisions to the standard should consider methods or parameters to eliminate momentary cessation while maintaining system reliability. Other functions within the inverter can cause momentary cessation to operate in a manner similar to a protective function. However, the focus for PRC-019 is on voltage-related functions.

   —Including dynamic active power-frequency control and reactive power-voltage control.

   —Momentary cessation has been observed in BPS solar PV facilities in all disturbances analyzed by NERC, including but not limited to the Blue Cut Fire, Canyon 2 Fire, Palmdale Roost, and Angeles Forest disturbances.
### Requested information

where it cannot be eliminated (for legacy equipment) or reduce the condition known as momentary cessation. If a controller is incapable of removing the momentary cessation functionality, then the momentary cessation programming should be set based on the capabilities of the inverter.

c. **Controller upgrades and/or changes** (e.g., firmware) – Specify that firmware upgrades are considered “system, equipment or setting changes” under Requirement R2 since these may impact DPR voltage control(s), protection, and limiters.

d. **Steady State Stability Limit (SSSL)** – Determine whether the “stability limits” language in Requirement R1.1.2 should be removed from the standard. [Manual SSSL theory is only applicable when a generator AVR is in manual operation mode; however, the standard specifically instructs an entity to assume the AVR is in automatic mode. This assumption is identified because it is industry standard to coordinate the underexcitation limiter with the SSSL since that is the most conservative approach for AVR operation. However, the protection settings typically coordinate with the machine capabilities and not the manual SSSL.]

e. **Synchronous condensers** – If item ‘d’ remains in the standard, determine whether SSSL should be considered for synchronous condensers. [A synchronous condenser operates in a manner similar to a synchronous generator in terms of voltage regulation and the associated excitation control system. The electrical quantities for a synchronous condenser match the quantities specified in the manual SSSL methodology; however, the machine does not have a prime mover and cannot output real power. This drastically reduces the machines operating region since the unit will only be able to absorb or generate reactive power.]

f. **Stability limits for other types of generation resources** – If item ‘d’ remains in the standard, verify whether a SSSL must be considered for asynchronous and non-rotating generation resources. [Current references to stability limits are all relevant to synchronous machines (AVR in manual mode, fixed excitation voltage, etc.). If consideration of stability is necessary, provide a methodology or implementation guidance for the industry to use (e.g. small signal stability, etc.).]

g. **Voltage drop across DPR collector system** – Determine whether the voltage drop across the collector system, bus, generator step-up (GSU) transformer, or other facilities should be considered for coordination.

h. **Time frame to perform coordination** – Revise the language in Requirement R2 to remove ambiguity surrounding the timeframe for performing coordination. [The current language can be interpreted as allowing the coordination to be performed 90 days after the “implementation of systems, equipment, or setting changes.” This would allow an entity to put a unit back into service without performing coordination; thus, jeopardizing reliability. The original SDT has confirmed that the 90-day time frame was for scenarios in which an entity discovered a miscoordination.]
Requested information

Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):

Costs may include updating firmware on DPRs, individual IBRs, park/plant controllers, and other associated equipment, and will vary depending on the approach taken to address the reliability-related risks stated above.

Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (e.g. Dispersed Generation Resources):

Synchronous generation and Dispersed Power Resources may be impacted by the revisions.

To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (e.g. Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):

The team should be made up predominantly by protection engineers with a background in generation protection (synchronous/DPR); preferably industry experts in this field. Additionally, IBR manufacturers and DPR EPC firms should be included because of the inherent knowledge of the capabilities and limitations of DPRs. Team members should have extensive understanding of generation protection concepts/schemes. In addition, they should have some knowledge of control systems (AVR, IBR’s, etc.)

Do you know of any consensus building activities\(^7\) in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.

No

Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so which standard(s) or project number(s)?

No.

Are there alternatives (e.g. guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.

The NERC SPCS initially attempted to develop Implementation Guidance; however, while developing the implementation guidance, the group determined that the standard required additional clarity for IBRs.

Reliability Principles

Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.

- **1.** Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
- **2.** The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
- **3.** Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

---

\(^7\) Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.
### Reliability Principles

- 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
- 5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
- 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
- 7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
- 8. Bulk power systems shall be protected from malicious physical or cyber attacks.

### Market Interface Principles

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<tr>
<th>Market Interface Principles</th>
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<tbody>
<tr>
<td>1. A reliability standard shall not give any market participant an unfair competitive advantage.</td>
<td>Yes</td>
</tr>
<tr>
<td>2. A reliability standard shall neither mandate nor prohibit any specific market structure.</td>
<td>Yes</td>
</tr>
<tr>
<td>3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.</td>
<td>Yes</td>
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<tr>
<td>4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.</td>
<td>Yes</td>
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### Identified Existing or Potential Regional or Interconnection Variances

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### For Use by NERC Only

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<tr>
<td>Draft SAR reviewed by NERC Staff</td>
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<tr>
<td>Draft SAR presented to SC for acceptance</td>
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<td>DRAFT SAR approved for posting by the SC</td>
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### Version History

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Generating Availability Data System (GADS) Data Request for Utility-Scale Solar Plants and Updates for GADS Wind and Conventional GADS

**Action**
Authorize posting for public comment

**Background**
NERC has required reporting of conventional generation inventory, performance, and event data since 2012. In 2015, NERC issued a Section 1600 data request to expand the collection of GADS data to include wind generation. Reporting of wind generation data became mandatory in 2018 with a phased-in approach; in 2020, the final phase of wind plants began reporting. The increasing penetration of solar generation has prompted the need for NERC to have information about utility-scale solar facilities whose operation may impact the bulk electric system.

In 2018, NERC and the GADS Working Group (GADSWG) began developing data reporting requirements for utility-scale solar facilities and connected energy storage at the plant. During the development of the data reporting requirements for solar facilities, gaps in the reporting requirements for wind reporting were identified, namely event reporting and connected energy storage at the plant. The expansion of data requirements for GADS Wind will improve NERC’s ability to evaluate performance of renewable and conventional generation and provide comparable reporting requirements for both wind and utility-scale solar generation.

Conventional GADS reporting of design data is currently limited to basic location information, (i.e., address details) and the Energy Information Administration code. Design data formerly collected by NERC on a voluntary basis is outdated. This limits NERC’s ability to conduct detailed analysis to evaluate whether certain types of unit configurations or key operating components are impacted by operating conditions such as extreme weather. As part of the modifications being requested in this GADS Data Request, NERC and the GADSWG propose to modify conventional GADS reporting to include limited design data by unit type and add a Contributing Operating Condition field.

Per NERC Rules of Procedure, NERC plans to notify FERC and post the GADS Data Request for a 45-day stakeholder comment period. NERC staff and the GADSWG will review the comments received and make appropriate revisions. Following the public comment period, the GADS Data Request will be provided to the RSTC for endorsement and to the NERC Board of Trustees for approval in the second half of 2020.

Proposed motion language:
“I move to authorize NERC staff to post the draft GADS Data Request for 45-day stakeholder comment period.”

**Summary:** (left blank for your notations)
Inverter-Based Resources Performance Task Force
BPS-Connected Inverter-Based Resource Modeling and Studies Technical Report

Action
Planning Committee Review

Background
The Inverter-Based Resources Performance Task Force (IRPTF) has performed various modeling and study activities in its efforts to complete assigned tasks. Additionally, the IRPTF members have conducted related activities to inform the group on topics under discussion. The results of these modeling and study activities have led to several key findings. The key findings can be categorized as originating from the NERC Alerts related to the Bulk Power System (BPS)-connected solar PV resource tripping events, IRPTF stability studies, and technical discussions on various topics at the IRPTF meetings. The IRPTF has documented these key findings along with recommendations in a technical report.

In general, the key findings and recommendations pertain to dynamic model quality and accuracy issues, the negative reliability impact of the use of momentary cessation, and study process improvements. They are framed in the context of ensuring reliable operation of the BPS in the face of increasing penetrations of BPS-connected inverter-based resources. This technical report provides industry with sound technical steps to address the identified issues with clear recommendations.

Proposed motion language, if applicable:
N/A

Summary
Leave Blank for meeting participant notes
Technical Report
BPS-Connected Inverter-Based Resource Modeling and Studies
March 2020
# Table of Contents

Preface ........................................................................................................................................................................... iii

Executive Summary ........................................................................................................................................................ iv

Key Findings .................................................................................................................................................................. vi

Introduction ................................................................................................................................................................... vi

Chapter 1: Inverter-Based Resource Modeling Activities .............................................................................................. 1

Industry Efforts to Update Dynamic Models ............................................................................................................... 3

WECC Solar Modeling Advisory Group ........................................................................................................................ 7

Challenges with Relying on MOD-026-1 and MOD-027-1 ........................................................................................... 7

Recommended Questions to Ask when Receiving Dynamic Models .......................................................................... 8

Growing Need for Electromagnetic Transient Modeling ............................................................................................ 9

Predominant Issues for Modeling Inverter-Based Resources ................................................................................... 11

Chapter 2: Reliability Studies of Inverter-Based Resources ........................................................................................... 15

Current Control Sensitives if Eliminating Momentary Cessation .............................................................................. 27

Appendix A: Model Verification Review .................................................................................................................. 38

Appendix B: Canyon 2 Fire Disturbance NERC Alert Follow-Up ............................................................................... 43

Contributors .................................................................................................................................................................. 48
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is divided into six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.
Executive Summary

The NERC Inverter-Based Resource Performance Task Force (IRPTF) and the industry have been working diligently on modeling and simulation activities in an effort to more accurately represent inverter-based resources in dynamic stability analyses and explore the impacts of inverter-based resources on BPS reliability. This report outlines the activities of the IRPTF and its members related to inverter-based resource modeling and studies. These activities are based on the following:

- NERC staff activities related to disturbance analyses, issuing NERC Alerts, and gathering data from these Alerts
- TP and PC efforts to improve the accuracy of RMS\(^1\) positive sequence dynamic models for inverter-based resources
- IRPTF modeling sub-team activities to perform interconnection-wide stability analyses
- IRPTF technical discussions and work product developments

Table A.1 of Appendix A provides a list of key findings and recommendations from all the industry and IRPTF activities that have occurred in the past couple years. These findings are separated into three distinct categories. Items A1–A6 focus on NERC Alert findings, items S1–S6 are associated with IRPTF studies, and items D1–D7 are based on technical discussions and industry work related to dynamic modeling needs. The following list is an abbreviated version of Table A.1, highlighting the modeling issues identified and study results obtained:

- **NERC Alert Findings:** These findings highlight systemic modeling issues with BPS-connected solar PV resources in the interconnection-wide base cases, with many dynamic models not matching the data provided per the NERC Alert process. Further, many GOs failed to provide any dynamic model as part of the NERC Alert process, and those that did mostly had modeling errors or inaccuracies that made the submitted models unusable to the TP and PC. Many entities stated they could MC yet did not provide any updated dynamic model to initiate these changes to be studied by the TP and PC. Therefore, it is unclear as to the extent of modeling inaccuracies in the interconnection-wide base cases at this time. The accuracy and reasonability of dynamic model parameterization is often overlooked by TPs and PCs due to lack of understanding of the dynamic models and lack of tools to effectively perform such validity checks. These issues illustrate the need to update the interconnection-wide base cases as quickly as possible with accurate dynamic modeling information for BPS-connected solar PV resources to ensure reliability studies are able to identify potential reliability issues.

- **IRPTF Studies Findings:** Stability studies highlighted degradation of BPS performance when MC is widely applied to solar PV resources, potentially causing BPS voltage and transient instability. MC also interacted with existing high voltage dc (HVDC) circuit controls and remedial action scheme (RAS) actions. This highlighted the need to eliminate MC to the extent possible. Studies using the most accurate available modeling information for BPS-connected solar PV resources showed that the BPS remains stable yet BPS performance is still degraded.\(^2\) This required applying extensive user-defined models that overlay on the existing models to more accurately capture the large disturbance behavior from solar PV resources on the BPS. Sensitivity studies were performed that showed that reactive current priority with voltage control enabled is the preferred default configuration for BPS-connected solar PV resources; however, detailed interconnection studies should determine tuning of control systems for each BPS-connected inverter-based resource. Lastly, IRPTF studies highlighted the need for more accurate protection system modeling to identify any potential interactions with inverter controls moving forward.

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\(^1\) Root-mean-square

\(^2\) Relative to what is currently modeled in the interconnection-wide base cases.
• **Technical Discussion Findings:** IRPTF and industry technical discussions have highlighted an array of modeling issues that need to be addressed in a timely manner, and are likely leading to some of the systemic modeling issues identified in this report. NERC MOD-026-1 and MOD-027-1 verification and testing activities are not adequately verifying the dynamic models relative to actual installed equipment performance for large disturbance response, leading to false expectations that these models are actually representative of installed performance. Incorrect parameterization of the dynamic models is likely caused by poor information sharing between the OEM, GO, TP, and PC, and is a contributor to many of the modeling issues. Similarly, Attachment A of Appendix 1 of the FERC Large and Small Generator Interconnection Procedures (LGIP/SGIP) does not mention solar PV resources and only briefly mentions wind power resources. Lack of specificity of modeling information may be leading to lack of detailed studies prior to interconnection. Further, it is unclear in these procedures what constitutes a “material modification” and how the technological change procedures should apply. Interconnection requirements should be broadly improved to ensure adequate modeling information is collected during interconnection and that any changes affecting the electrical performance of the facility are studied prior to implementation by the GO. Interconnection-wide case creation practices will also need to evolve as instantaneous penetrations of inverter-based resources continues to increase. Many entities are experiencing a need for more advanced electromagnetic transient (EMT) modeling in areas of high penetrations of BPS-connected inverter-based resources, and EMT simulations are becoming standard practice during the interconnection processes.

Without attention to the recommendations described in Appendix A, TPs and PCs are limited in their ability to ensure reliable operation of the BPS in the face of increasing penetrations of BPS-connected inverter-based resources. The efforts of the NERC IRPTF have illustrated a need to have TPs and PCs along with GOs and equipment manufacturers and develop take timely actions to correct the modeling issues identified. A shift in the study approaches and tools may also be warranted in many cases. This technical report provides industry with sound technical steps to address these issues, with clear recommendations throughout. All points have been thoroughly vetted by IRPTF members. This ensures that the perspectives of TPs, PCs, RCs, GOs, GOPs, and equipment manufacturers have been considered and addressed. As new technologies continue to connect to the BPS, there will be a continued need to work out these issues in this manner.

Chapter 1 of this technical report focuses on modeling activities and issues related to BPS-connected inverter-based resources; Chapter 2 describes system reliability studies performed by the IRPTF focusing on the Western Interconnection, including sensitivity analyses on various inverter controls considerations. Appendix A provides a complete list of key findings and recommendations from this report. Appendix B discusses model verification issues regarding large disturbance behavior of inverter-based resources. Appendix C describes follow-up findings after the Canyon 2 disturbance NERC Alert.

The report is applicable for TPs, PCs, RCs, and GOs of BPS-connected inverter-based resources (particularly solar PV resources). Each entity is encouraged to review the key findings of this report and implement the recommendations set forth, as applicable.
Introduction

The rapid growth in inverter-based resources connected to the BPS across North America has challenged TPs, PCs, RCs, GOs, and inverter manufacturers with ensuring the models used to represent these resources in steady-state powerflow, dynamics, and short circuit studies sufficiently represent the actual behavior of these resources. NERC activities have initiated a fairly extensive industry-wide focus on model improvements for inverter-based resources, including efforts within NERC, in the NERC IRPTF, and by industry to improve their modeling and simulation practices.

NERC IRPTF Modeling and Studies Sub-Group

NERC IRPTF has been working on modeling and dynamic simulations of BPS reliability and various inverter-based resource modeling issues over the past few years since the studies related to the Blue Cut Fire. The group was initially formed to analyze the potential of widespread MC possibly affecting frequency stability in the Western Interconnection. Following that work, the team concluded that frequency stability was not at risk; however, transient stability issues could possibly arise across all Interconnections if MC continued to be used as a predominant form of ride-through operation moving forward. This led to recommendations that MC be mitigated to the extent possible. Subsequent studies identified that most BPS-connected solar PV resources do not have their large disturbance behavior accurately modeled (specifically not accurately representing MC or disturbance ride-through). The group also supported the development of the NERC Alert following the Canyon 2 Fire disturbance. Most recently, the group has been analyzing the data and information received from their respective GOs following the Canyon 2 Fire NERC Alert. The discussions and analyses that have transpired since then have identified a number of modeling and study recommendations that are captured in this report.

NERC Disturbance Analyses and NERC Alerts

Following the Blue Cut Fire and Canyon 2 Fire disturbances, NERC issued Alerts to gather data to understand the extent of the conditions regarding inverter operating modes and to recommend mitigating actions to address potential reliability issues related to inverter-based resource performance. In particular, the NERC Alert following the Canyon 2 Fire disturbance focused primarily on modeling issues. Specifically, the Alert provided recommendations for modeling MC for existing solar PV resources as well as accurately modeling updated controls for potential changes to eliminate MC. In particular, the NERC Alert stated that GOs should perform the following:

**Recommendation 1a:** Ensure that the dynamic model(s) being used accurately represent the dynamic performance of the solar facilities. Refer to the Modeling Notification published on this topic. If the inverters at the solar facility use MC, update the dynamic model(s) to accurately represent MC and provide the model(s) to the Transmission Planner and Planning Coordinator (to support NERC Reliability Standard TPL-001-4 studies) and to the Reliability Coordinator, Transmission Operator, and Balancing Authority (in accordance with NERC Reliability Standards TOP-003-3 and IRO-010-2). If no change is required in the model(s), a written notification that the previously provided model(s) accurately captures the dynamic behavior of the solar PV facility should be provided.

**Recommendation 1b:** Work with their inverter manufacturer(s) to identify the changes that can be made to eliminate MC of current injection to the greatest extent possible, consistent with equipment capability. For inverters where MC cannot be eliminated entirely (i.e., by using another form of ride-through mode), identify the changes that can be made to MC settings that result in:

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6 [https://www.nerc.com/pa/rrm/bpsa/Pages/Alerts.aspx](https://www.nerc.com/pa/rrm/bpsa/Pages/Alerts.aspx)
a) Reducing the MC low voltage threshold to the lowest value possible.
b) Increasing the MC high voltage threshold to the highest value possible, at least higher than the NERC Reliability Standard PRC-024-2 voltage ride-through curve levels.
c) Reducing the recovery delay (time between voltage recovery and start of current injection) to the smallest value possible (i.e., on the order of 1-3 electrical cycles).
d) Increasing the active power ramp rate upon return from MC to at least 100% per second, unless specific reliability studies have demonstrated otherwise.

Provide these proposed changes, and an accompanying proposed dynamic model, to their TP and PC. GOs should provide these proposed models, according to their Transmission Planners'/Planning Coordinators’ procedures for modifying existing facilities, as soon as possible.

The NERC Alert subsequently requested that the TP, PC, TOP, and RC who are receiving the recommendations in the NERC Alert perform the following:

**Recommendation 6a:** Track, retain, and use the updated dynamic model(s) (and any other pertinent information gathered from this NERC Alert) of existing resource performance that are supplied by the Generator Owners to perform assessments and system analyses to identify any potential reliability risks related to instability, cascading, or uncontrolled separation as soon as possible.

**Recommendation 6b:** Track, retain, and analyze the proposed dynamic model(s) supplied by the Generator Owners that indicate their proposed changes (based on Recommendation 1b) to eliminate MC to the extent possible. Based on the analysis, approve or disapprove the potential changes based on reliability risks related to instability, cascading, or uncontrolled separation as soon as possible.

The NERC Alert addressed two key aspects of modeling inverter-based resource dynamic performance:

1. Ensuring that the currently used dynamic models accurately represent the actual behavior of the inverter-based resources; and
2. Ensuring that the GO is coordinating with the TP and PC to make changes to inverter controls to eliminate MC by providing an updated dynamic model to the TP and PC for study and acceptance of the proposed changes (aligning with FAC-002-2).

**Modeling Notification for NERC Alert**
To support the Canyon 2 Fire NERC Alert recommending actions to accurately model existing controls of inverter-based resources as well as proposed changes to controls (through updated modeling and studies) to support BPS reliability, the NERC IRPTF modeling sub-group developed a Modeling Notification regarding recommended practices for modeling MC. While the NERC Alert recommended eliminating MC to the extent possible, it also highlighted the immediate need to accurately model solar PV large disturbance controls correctly (namely, the widespread use of MC). The Modeling Notification provided clear guidance on how to update models and key parameter values in the models, to reasonably represent MC in RMS positive sequence stability programs. Refer to the Modeling Notification for more details.

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Chapter 1: Inverter-Based Resource Modeling Activities

A significant amount of activities focusing on reliable integration of BPS-connected inverter-based resources, particularly on the modeling aspects, have taken place in the NERC IRPTF over the past two years. These activities have led to improvements to TP and PC modeling practices, identified systemic modeling challenges facing the industry, and led to recommended improvements to modeling and studies required per NERC FAC-001-3 and FAC-002-2 Reliability Standards. This chapter documents many of these activities as well as the key findings and recommendations moving forward.

Canyon 2 Fire NERC Alert Findings

As described, a NERC Alert was issued following the Canyon 2 Fire disturbance that required mandatory data reporting and recommended specific changes to performance and modeling of BPS-connected solar PV resources. Following the submittal of data from GOs regarding large disturbance performance, NERC was particularly focused on ensuring that the TPs and PCs received the data as well (per the recommendations of the NERC Alert) and were taking actions to ensure that the interconnection-wide planning models were being updated to reflect actual installed equipment. Further, NERC was interested in the types of studies being performed by TPs and PCs to ensure that the proposed changes to solar PV inverters were being made accordingly by the GOs that reported this capability.

Prior to the NERC Alert, in many cases, TPs and PCs had insufficient information to determine whether the modeling data provided was a reasonable representation of the behavior of the resource. For example, most submitted models for resources employing MC in the field did not capture this behavior in the dynamic models; however, TPs and PCs were unaware of the discrepancy because there was no means of verifying this modeling data without the NERC Alert data gathered.

Upon completion of the timelines used in the NERC Alert for data submittal to NERC and modeling information submittal to the TPs and PC, NERC followed up with each TP and PC that should have received data from their respective GOs of solar PV resources. Appendix C provides a detailed anonymous review of a selection of entities that provided follow-up information. The key takeaways from these responses include:

- The majority of TPs and PCs stated that they received little or no updated dynamic models for the existing solar PV resources following the NERC Alert process. Similarly, nearly no solar PV facilities provided dynamic models of the proposed changes that could be made to improve performance.
  - TPs and PCs stated that because the updated models were not provided by the GO, no further action was taken to perform system studies to ensure reliability.
  - Some TPs and PCs also stated that no follow-up actions were taken to request or collect the updated dynamic models from the GO to proactively address the known modeling issues. However, some TPs and PCs are being very diligent about these follow-ups outside of the NERC Alert process (i.e., using market rules and other requirements).
  - Some TPs and PCs stated that they did additional outreach to GOs of solar PV facilities but were met with either unwillingness to support such initiatives or no concrete timelines as to when the updates would be performed. Very few entities mentioned utilizing MOD-032-1 Requirement R3 to get the dynamic models updated, even with known modeling issues present (based on the discrepancies between NERC Alert data and previously provided dynamic models).
    - Entities that did additional outreach nearly all stated that a significant amount of effort and education was needed during these follow-ups to ensure the correct models and parameters were provided by the GO.

• Nearly every TP and PC that did receive updated dynamic models from solar PV resources following the NERC Alert stated that the models provided had errors or deficiencies that made them unusable. These issues included the following:
  ▪ The dynamic models provided were not the appropriate models to represent the resource being modeled or are considered obsolete models.
  ▪ The electrical controls model submitted was reec_b; however, the resource currently uses MC. The reec_b dynamic model is not able to reasonably represent MC with sufficient detail.
  ▪ The dynamic model parameters did not match the information provided following the NERC Alert (i.e., the spreadsheet for MC performance required to be submitted by the GO to NERC did not match the modeling data provided to the TP or PC).
  ▪ The dynamic models would not initialize properly or provide a flat run simulation for no disturbance.
• Multiple TPs and PCs stated that they received updated dynamic models and that those models are reasonable. However, upon further vetting by NERC it was determined that the dynamic models had incorrect parameterization or were not a reasonable representation of the MC characteristic (e.g., the models submitted were reec_b even though the resource uses MC). This identified a systemic lack of verification of the parameterization of the dynamic models by TPs and PCs, as well as possible systemic issues regarding the understanding of these dynamic models compared to actual performance of solar PV resources.
• Some TPs and PCs stated that they rely solely on the MOD-026-1 and MOD-027-1 processes to update dynamic models for their base case submittals. However, as described in this report, this may lead to systemic modeling issues for verifying the accuracy of these models for large disturbance behavior of inverter-based resources.
• A small group of TPs and PC are being very proactive in addressing known modeling issues using either MOD-032-1 Requirement R3 or other mechanisms such as market rules in annual modeling submittal requirements. These examples, while rare, are good illustrations of how TPs and PCs should be proactively verifying the dynamic models and their parameters against actual installed equipment settings.
• Most BPS-connected solar PV resources owners stated in their response to the data request for the NERC Alert that they could eliminate momentary cessation or that the momentary cessation settings could be changed to improve performance. However, little to no dynamic models were provided for those proposed changes. Therefore, it is unclear, based on the information at hand, whether those changes were made and whether the dynamic models have been updated to adequately reflect either the existing or proposed settings.
• Information from only about one-half of the installed capacity of BPS-connected solar PV resources (at least in the Western Interconnection) was collected as part of the NERC Alert process based on the size of resources and their designation as BES or non-BES resources. The extent of model accuracy for those resources that did not respond to the NERC Alert is unknown.

These findings from reviewing and analyzing the responses provided by GOs during the NERC Alert and by TPs and PCs as part of follow-up activities by NERC following the NERC Alert illuminate some major challenges to modeling of BPS-connected inverter-based resources (particularly solar PV resources). Known modeling issues exist and may continue to exist, and may be attributable to issues related to modeling submittals during the interconnection study process or annual base case creation process. It is clear that there is a lack of verification of reasonable parameterization of the dynamic models and likely a lack of understanding of these models by industry.
Industry Efforts to Update Dynamic Models
Prior to the activities following the Canyon 2 Fire disturbance and subsequent NERC Alert, SCE and CAISO attempted to collect updated generation dynamic models in 2017. This was in response to the unexpected performance observed by solar PV facilities during disturbances that occurred on SCE’s system in 2016. The disturbances brought to light that the existing models provided by the GOs were not accurate for large disturbance behavior. To address this issue, SCE in coordination with the CAISO sent GOs data requests seeking updated or revised generation model data. To seek compliance with the data request, the request letters referenced MOD-025-2, MOD-026-1, MOD-027-1, MOD-032-1, PRC-24-2, the CAISO’s Business Practice Manual (BPM) and CAISO’s Fifth Replacement FERC Electric Tariff Section 24.8.2. SCE sent approximately 120 data request letters to GOs. However, most of the data received from the GOs corresponding to the data request were deficient. During this process, SCE observed the following challenges:

- GOs stated that the data request caused financial burden since they had to hire engineers or consultants to collect the data and develop the dynamic models.
- GOs stated that some of the data required field verification testing, which would not be performed until the next maintenance schedule.
- GOs owning non-BES facilities, and therefore are not subject to NERC Reliability Standards for those facilities, were reluctant to provide any updated data given that it was not enforceable.

In addition to the GOs being reluctant to submit updated generation model data, SCE also experienced data quality issues. GOs were able to meet MOD-032-1 requirements by providing minimum amounts of data and not necessarily data meeting the quality expected by SCE (and requested by SCE).

The California ISO (CAISO), in coordination with Southern California Edison (SCE), Pacific Gas and Electric (PG&E), and San Diego Gas and Electric (SDG&E), started a model update process in 2018 following the Canyon 2 Fire NERC Alert. This process seeks modeling improvements for all generation within the CAISO market. Figure 1.1 shows an example of the process for updating the modeling data, specifically illustrating SCE process. The process includes:

- **Data Package Creation:** CAISO and its Participating Transmission Owners (PTOs) create a package that is sent to each GO to gather updated modeling data, with specified model data details and data formats.
- **GO Data Gathering:** GOs collect the necessary modeling information, and provide this data to CAISO within 120 days from receiving the request (per each facility).
- **CAISO and PTO Review:** CAISO and its PTOs perform a detailed review of the data collected to ensure that the model initializes correctly, the model performs acceptably under large disturbance conditions, all model parameters match the data provided in the NERC Alert, and all model parameters pass reasonability checks. When deficiencies in the submitted data are identified, CAISO will send feedback to the GO within 90 days.
- **GO Deficiency Cure:** Where applicable, the GO has 60 days to address the deficiencies identified by CAISO and its PTOs.
- **Second CAISO and PTO Review:** Following re-submission of the modeling data, CAISO and its PTOs have 90 days to again review the modeling data.
All generating resources operational on or before September 1, 2018 and participating in the CAISO market are scheduled to provide updated modeling data in eleven phases. Table 1.1 shows the schedule and composition of resources in each phase. Resources utilizing MC and larger capacity resources were included in earlier phases due to the critical nature to address any modeling deficiencies for those resources. Figure 1.2 shows the status of submissions received as of September 25, 2019. As of that date, CAISO has received updated models from 109 resources constituting 13,915 MW of capacity. 39 of those facilities (3,844 MW) are solar PV resources and 21 of those facilities use MC (2,672 MW). 101 submissions were reviewed by the time of documenting this report. Only 6 model submissions were accepted. 95 facilities were identified as deficient, and 85 (10,923 MW) of those are still seeking a correction to the deficiency.

A similar review was performed by SCE, as shown in Figure 1.3. A total of 29 (3,707 MW) solar PV facilities meet the criteria for modeling assessment. Data requests have been received from 18 (1,928 MW) facilities. Of those, 15 (1,867 MW) use MC and all those models were reviewed. Every model submitted had deficiencies identified and SCE and CAISO provided that feedback to the GOs to address within the timelines described above. The review identified the following most common modeling deficiencies:

- The GO submitted the reec_b dynamic model instead of reec_a model. The reec_b model is unable to accurately model MC, and is considered an obsolete model in WECC (its use is disallowed moving forward).
- The GO submitted dynamic models with parameters for MC that do not match the actual settings data submitted as part of the NERC Alert.
- The GO did not provide a dynamic model that includes MC even though the GO provided data following the NERC Alert.

PG&E is also actively participating in the review of the modeling data supplied by GOs in regards to the CAISO data requests. Figure 1.4 shows a timeline of all phases the status of PG&E review in each. During report-outs at IRPTF meetings, PG&E highlighted that these analyses are resource demanding considering that each generator data sheet has 190 equipment data items for review and cross-checking. The model data reviewers need to fill out a
comprehensive checklist for each generator. The PTOs are identifying any data quality deficiencies in the GO data submissions. These data quality deficiencies include, but are not limited to, deviations from applicable reliability standards, PTO interconnection handbook, expected steady-state or dynamic performance results, and reasonable values for generator technology type and size.

As the CAISO gathers updated data and information for modeling, they are reporting the updated model data to WECC as the MOD-032 Designee for creating the interconnection-wide base cases in the Western Interconnection. Until the full process is completed, potential modeling discrepancies for BPS-connected inverter-based resources may exist in the WECC base cases.

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Chapter 1: Inverter-Based Resource Modeling Activities

Figure 1.2: Status of Modeling Improvements at CAISO (September 25, 2019)
[Source: CAISO]

Figure 1.3: SCE Status Update for Modeling Improvements
Chapter 1: Inverter-Based Resource Modeling Activities

In April 2019, NERC and WECC jointly held a meeting with transmission entities to coordinate activities related to modeling and system analysis for increasing penetrations of BPS-connected inverter-based resources. One of the outcomes of this meeting was a request for WECC to form an ad-hoc group consisting of the meeting attendees to review the results from the NERC Alert data following the Canyon 2 Fire disturbance. The WECC Solar Modeling Advisory Group (SMAG) was formed to focus on accurate modeling of existing inverter-based resources and to ensure that all BPS-connected solar PV resources modeled in the WECC Master Dynamics File for interconnection-wide base cases accurately represent the installed resources. The goal of this activity is to coordinate modeling improvements across TP and PC footprints to ensure all updates get integrated in the base case creation process.

As of the time of writing this report, the WECC SMAG has not verified the validity of dynamic models for any BPS-connected inverter-based resources in the WECC base cases. One entity has reviewed the data in their footprint and identified modeling errors needing attention.

### WECC Solar Modeling Advisory Group

In April 2019, NERC and WECC jointly held a meeting with transmission entities to coordinate activities related to modeling and system analysis for increasing penetrations of BPS-connected inverter-based resources. One of the outcomes of this meeting was a request for WECC to form an ad-hoc group consisting of the meeting attendees to review the results from the NERC Alert data following the Canyon 2 Fire disturbance. The WECC Solar Modeling Advisory Group (SMAG) was formed to focus on accurate modeling of existing inverter-based resources and to ensure that all BPS-connected solar PV resources modeled in the WECC Master Dynamics File for interconnection-wide base cases accurately represent the installed resources. The goal of this activity is to coordinate modeling improvements across TP and PC footprints to ensure all updates get integrated in the base case creation process.

As of the time of writing this report, the WECC SMAG has not verified the validity of dynamic models for any BPS-connected inverter-based resources in the WECC base cases. One entity has reviewed the data in their footprint and identified modeling errors needing attention.

### Challenges with Relying on MOD-026-1 and MOD-027-1

NERC MOD-026-1 focuses on verification of data for generator excitation control system or plant volt/var control functions and MOD-027-1 focuses on verification of data for turbine-governor and load control or active power-frequency control functions. Specifically, MOD-026-1 states in footnote 1 that the excitation control system for aggregate generating plants (i.e., wind and solar PV) includes the volt/var control system including the voltage regulator and reactive power control system controlling and coordinating plant voltage and associated reactive capable resources. This language is slightly ambiguous on whether the verification activities include the inverter-level parameter values of the dynamic models. Various testing engineers and entities have stated that they are uncertain as to whether the standard applies to the plant-level parameters or the aggregate representation of the inverter-level settings.

![Figure 1.4: PG&E Timeline for Modeling Improvements [Source: PG&E]](image-url)
Most commonly, verification test reports for inverter-based resources involve a small set of small disturbance tests including, but not limited to, the following:

- Capacitor switching test
- Plant-level voltage or reactive power reference step test
- Plant-level frequency reference step test
- Plant-level frequency play-in or step test

These tests do not perturb the generating resource such that the parameter values that dictate the large disturbance behavior\(^\text{11}\) of the resource are verified in any way. While blatantly incorrect model parameters may be identified during these tests, the tests do not verify that the parameters selected for the model accurately capture the dynamic behavior of the resource. Refer to Appendix B showing the common suite of generic library dynamic models used to represent a solar PV and Type 4 wind plants. The tables in Appendix B list the parameters for each model and describe whether the parameters can be verified using commonly applied verification tests (i.e., tests that demonstrate a match between simulated and actual response). The Appendix B materials show that the majority of parameters are not verified by these tests directly; large disturbance behavior is overlooked.

This gives a false impression to TPs and PCs that the full set of parameters are verified for use in planning studies. Improvements are needed to the NERC MOD standards to ensure that critical parameter values are verified in some way, and that documentation is provided that justifies all parameter values. For example, testing engineers could document inverter-level settings, provide specification sheets (when available), perform and demonstrate engineering calculations, and perform other activities to demonstrate verification of parameters beyond testing activities only. However, these actions are not requirements in MOD-026-1 and MOD-027-1. Thus, these additional steps are often not documented or proven in MOD-026-1 and MOD-027-1 test reports for inverter-based resources, leading to the problems previously mentioned.

This issue is one of the predominant reasons why ride-through operation modes such as MC were able to persist and promulgate throughout BPS-connected inverter-based resources for so long.\(^\text{12}\) The dynamic models did not accurately represent this large disturbance behavior since certain key parameters that govern the response under a large disturbance were incorrectly parametrized; however, the same plants were able to provide verification reports that demonstrated that the small disturbance behavior driven mainly by plant-level control settings reasonably matched.

**Recommended Questions to Ask when Receiving Dynamic Models**

As described throughout the paper thus far, systemic models issues have identified by NERC and the IRPTF during disturbance analyses involving solar PV resources and their dynamic behavior to large disturbance events. Many of these issues stem from insufficient questions being asked by TPs and PCs when receiving dynamic modeling information for inverter-based resources. For this reason, IRPTF has developed a list of questions that should be asked for any modeling submittal provided by GOs of inverter-based resources. These questions involve validating to some degree, through corroboration with additional data sources, confirmation from the inverter manufacturer or other procurement contractor setting up the plant level controller or other control systems, that the dynamic models sufficiently represent the behavior of the installed equipment. Questions that should be asked include, but are not limited to, the following:

\(^{11}\) Large disturbance behavior involves large changes to terminal voltage, frequency, or phase. These conditions occur during fault events, which are the most commonly studied contingencies for planning assessments and interconnection studies.

\(^{12}\) In addition to the reec\_b (rather than reec\_a) model initially being recommended for BPS-connected solar PV resources, which does not include the ability to accurately model MC.
Chapter 1: Inverter-Based Resource Modeling Activities

- What type of BPS-connected inverter-based resource facility is being represented (e.g., a solar PV, wind, battery energy storage, or hybrid facility)?

- Do the steady-state and dynamic models provided meet the list of acceptable models established by the TP and PC, and do the models provided reasonably represent the resource?

- Is a oneline diagram provided to validate that the steady-state powerflow model is a reasonable representation of the equivalent generating resource and associated components within the plant? Does the powerflow model meet the recommended modeling practices used by the TP and PC?

- What make, type, and models of inverters and other relevant controls equipment are represented by these dynamic models? Were the inverter specification sheets and settings used to develop these dynamic models?

- Do the control modes set in the installed inverters and plant-level controls match the flags and settings configured in the dynamic models (e.g., voltage control versus reactive power control, current priority, and active power-frequency controls)?
  - Do the settings or configuration of these modes ever change in the installed equipment? If so, when and why? Do the dynamic models provided match all the expected settings and configurations for major performance capabilities?
  - Can the models adequately represent the performance of the plant for all these modes by switching the flags and settings, or is the model only valid for the indicated control mode?

- Are appropriate protection models or settings provided to the TP and PC to fully understand the potential ways in which the resource may trip or cease injection of current during abnormal operating conditions?
  - Are any of these settings out of the ordinary or restrictive beyond expected performance requirements set by the TO or by other relevant requirements?
  - Does the TP and PC have full understanding of all the possible protections and associated settings that may operate to trip the inverters?

- Is information provided that describes how the resource returns to service following any cessation of current from the BPS or following a trip?

This list of questions is not intended to be comprehensive; rather, it is intended to help TPs and PCs facilitate sufficient data collection such that BPS-connected inverter-based resources can be adequately modeled in system planning studies to ensure BPS reliability into the future. TPs and PCs are encouraged to adopt these types of questions into their interconnection process or annual case creation process.

Growing Need for Electromagnetic Transient Modeling

As inverter-based resources continue to interconnect to the BPS across North America, TPs and PCs are faced with challenges relying solely on the RMS positive sequence dynamic models to ensure reliable operation of the BPS. The following challenges have been identified in an increasing number of networks across North America and around the world:

- The RMS positive sequence simulation platforms, by design, are generally not suitable for capturing the dynamic response of inverter-based resources for unbalanced fault conditions.

- Due to the aforementioned point, any individual phase-based controls or protection cannot generally be modeled to complete accuracy in an RMS positive sequence simulation platform. For this reason, the RMS positive sequence dynamic models have limitations in precisely assessing ride-through performance during unbalanced faults often performed during interconnection studies. Approximations and engineering
judgment can be applied after extensive detailed simulations. However, applicability of these approximations is still uncertain.

- In areas of high penetration of inverter-based resources or low short circuit strength networks, the existing state-of-the-art generic RMS positive sequence dynamic models may encounter numerical issues that pose challenges for TPs and PCs to trust the results obtained from these studies. There are, however, beta versions of new generic RMS positive sequence models that have shown numerical robustness in low short circuit networks and are being introduced in various simulation platforms. In addition, spurious spikes in electrical quantities in positive sequence RMS simulations can occur at any bus, caused by sudden changes in inverter terminal voltage phase angle due to the network bus voltages being algebraic variables instead of differential equations as in EMT programs. These limitations need to be well understood by planning engineers.

- The RMS positive sequence dynamics models do not include the real-code behavior of inverter-based resources, and often involve engineering judgment based on controller block diagrams used in representing the actual performance of these complex power electronic resources. In the generic models, these simplifications are based on ensuring that the trend of the response is still captured accurately. However, a gap exists in identifying the exact thresholds at which inverter and plant protection would activate, which could be dependent on knowledge of the real code within the control systems.

- Due to the numerical issues and simplified modeling assumptions described above, the existing state-of-the-art generic RMS positive sequence dynamic models are often unable to identify controls instability or controls interactions with neighboring facilities\textsuperscript{13} or sub-cycle inverter tripping. Subsynchronous control interactions (SSCI) are not identifiable by these models by design of the simulation platform (i.e., fundamental frequency positive sequence simulations). Therefore, the most commonly used planning tools are not able to capture phenomenon like SSCI.

- The existing\textsuperscript{14} state-of-the-art generic RMS positive sequence dynamic models do not represent phase lock loop dynamics and other inner loop (small time constant) controls that often dictate the dynamic behavior and changes in control modes for inverter-based resources. Due to the lack of PLL dynamics and inner control loop modeling in the RMS positive sequence dynamic models, these models are unable to accurately represent the on-fault current contribution from inverter-based resources as well as any fast controls issues that may arise under low short circuit strength conditions. This can, however, change once the new generation of generic positive sequence models become part of the standard library of models.

The combination of these modeling challenges drives the growing need for EMT modeling\textsuperscript{15} and studies for inverter-based resources, particularly in areas of growing penetration of inverter-based resources or low short circuit strength. These areas may be wider areas of the BPS or may be local pockets of inverter-based resources that often do not include any nearby synchronous generation or loads. The NERC Reliability Guideline: Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources\textsuperscript{16} recommends including real-code EMT modeling requirements for all newly interconnecting inverter-based resources to the BPS and also recommends benchmarking the RMS positive sequence dynamic models with those EMT models. This documentation should be provided during the interconnection process such that the interconnection studies performed by the TP and PC can identify any BPS reliability issues at the time of interconnection and also into the future.

\textsuperscript{13} Such as with other inverter-based resources, series compensated transmission circuits, and HVDC facilities.

\textsuperscript{14} There are, however, beta versions of new generic RMS positive sequence models that have representation of these controls and have shown accurate behavior.

\textsuperscript{15} There are challenges with migrating towards large-scale EMT modeling and studies. Therefore, it is important to understand which situations may warrant EMT modeling and to have suitable information and models available to perform EMT simulations when needed.

All the issues described above are dependent on accurate parameterization of the models to match the installed equipment in the field. Inaccurate parameterization of any model (RMS positive sequence or EMT) can lead to misidentification of issues, which can be mitigated to some extent by accurate parameterization. Some guidelines in ensuring accurate parameterization can be obtained by asking the OEM for data regarding: type of facility, inverter modes of operation, control settings, ride-through performance, unusual or restructure protection settings, reconnection and recovery times, etc.

**Predominant Issues for Modeling Inverter-Based Resources**

Over the past few years as IRPTF has continued to review modeling data and support the NERC Alert process, a number of modeling issue have arisen. These have been documented by IRPTF here as a reference for future activities to improve modeling practices in the future. The predominant modeling issues for BPS-connected inverter-based resources (specifically solar PV resources) include, but are not limited to, the following:

- Dynamic models provided do not meet basic model quality checks. These include acceptable dynamic model initialization in the interconnection-wide base case, flat performance during a no-disturbance simulation, and positive damping for an otherwise stable simulation. These issues are caused mainly by incorrect parameterization of the dynamic models.

- Dynamic models are provided in the incorrect format as specified by the TP and PC in their modeling requirements. For example, the wrong simulation platform model structure may be used, or data may be provided in a tabular format rather than the actual dynamic model setup.

- The dynamic models or model parameters that have been provided for use in the interconnection study process and annual interconnection-wide base case creation do not match the information provided by the GO regarding the actual installed control settings for large disturbance behavior. For example, the reec_a model was provided but the dynamic model parameters for representing MC do not match the data provided by the GO per the NERC Alert.

- The dynamic models use reec_b rather than reec_a even though the resource uses MC during large disturbance behavior. The reec_b model does not reasonably capture MC response characteristics and reec_a model is recommended for BPS-connected inverter-based resources at this time. WECC has published a white paper describing the steps to convert the dynamic models from reec_b to reec_a; however, it is apparent that these recommendations are not being applied widely by industry.¹⁷

- Dynamic models are provided that appear “suspicious” in that they are using exactly the same parameter values used as default values in the simulation software manuals or that the model parameters for all dynamic models submitted match a wide array of other plants already modeled in the base case. It is unlikely that every control setting is exactly the same for a large number of plants; each control system should be tuned during the interconnection process and during commissioning to provide the optimal response for the locally connected network to which it is connected.

- The dynamic models are incorrectly parameterized with parameter values that are not coordinated appropriately. For example, coordinating the Vdip parameter with other MC parameters and VDL table values is critical for achieving the appropriate response. Further, coordinating the reactive current controls and Ip and Iq prioritization settings are essential to avoid spurious overvoltage conditions post-fault. Parameterization of these models is extremely complex and requires experts in this area to make changes to model settings due to all these interactions between parameter values and models.

- Anecdotally, IRPTF members and NERC staff have heard multiple times of plants making changes to control settings without providing a dynamic model to the TP and PC, nor requesting approval from the applicable

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¹⁷ [https://www.wecc.org/Reliability/Converting%20REEC_B%20to%20REEC_A%20for%20Solar%20PV%20Generators.pdf](https://www.wecc.org/Reliability/Converting%20REEC_B%20to%20REEC_A%20for%20Solar%20PV%20Generators.pdf)
transmission entities before these changes are made.\textsuperscript{18} The GOs and GOPs have stated that these changes are not considered “material modifications” and therefore can be made without prior approval or notification.

- There is a lack of information available for TPs and PCs to verify whether the dynamic models are a reasonable match to actual installed equipment. TPs and PCs have stated that while the commonly used small-disturbance tests are performed for MOD-026-1 and MOD-027-1 compliance, the TP and PC do not receive detailed reports that describe how each model parameter was or was not verified. Therefore, there is little to no data to use to verify that the dynamic models are set appropriately. Until the NERC Alert recommended GOs to provide data to TPs and PCs regarding large disturbance behavior of the actual installed equipment, it was expressed by multiple TPs and PCs that this data was not readily available.

- While the interconnection process often states that as-built settings must be provided some time period after the commercial operation date of the resource, multiple transmission entities have stated that they are very challenged in enforcing those requirements once the plant has entered commercial operation, and that receiving updated dynamic models through additional data requests have proved fruitless.

- For many entities, EMT models are not provided as part of the interconnection study process. EMT models are extremely difficult to acquire after-the-fact once the resource has been in-service for a period of time. This is due to many different reasons, but poses a challenge to systems that are experiencing a rapid evolution of generation technologies. Without receiving EMT models up-front during the interconnection process, some TPs and PCs are faced with using significant assumptions for resource performance while performing EMT simulations unless other requirements such as market rules are enforced.

- Detailed studies with the most up-to-date available data for both BPS-connected inverter-based resources as well as distributed energy resources (DERs) are not being widely performed. While the IRPTF studies manually updated the dynamic models for BPS-connected solar PV resources, DERs were not considered in those studies. Conversely, studies of DER using the most accurate data available are likely using the dynamic models for BPS-connected inverter-based resources provided in the interconnection-wide base cases which have systemic modeling issues identified in this report. Similarly, entities performing annual planning studies are required to use the data provided per MOD-032-1, which also may include the systemic modeling issues mentioned.

- Many of the more common stability issues observed during high-penetration inverter-based resource conditions are not easily detectible using the existing state-of-the-art RMS positive sequence stability simulations. Issues with controls interactions, controls instability, subsynchronous control interactions (SSCI), and other issues during low short circuit strength conditions require detailed EMT simulations that are not commonly performed during the annual planning process.

- The commercially available simulation tools most commonly used by TPs and PCs lack the reporting tools and capabilities to easily deduce necessary metrics for an increasingly variable and inverter-based generation mix. These may include: amount of on-line contingency reserves, amount of on-line frequency responsive reserves, amount of total on-line resources by type, amount of on-line resources with certain performance characteristics (e.g., MC), total system inertia, short circuit ratio-based metrics, and other useful indicators.

- Modeling issues are addressed in silos by one organization that may or may not be sharing their updated dynamic models and parameterization of those models with neighboring entities. Issues identified in Chapter 2 illustrate how modeling issues in one area could have a significant impact on neighboring areas, and need to be communicated to all neighboring entities, particularly if the controls begin interacting with each other.

\textsuperscript{18} This applies to both BPS-connected synchronous generators as well as inverter-based resources.
Modeling Issues and the Interconnection Study Process

Discussions during IRPTF meetings and modeling team meetings focused on identifying potential root causes to the modeling errors from the start of newly interconnecting resources to the BPS. This led IRPTF to review at a high level the interconnection process and identify some key factors that may be attributed to some of the modeling deficiencies observed to-date. For the purposes of this discussion, the Large Generator Interconnection Procedures (LGIP) and Large Generator Interconnection Agreement (LGIA) are used; however, these same concepts would apply to the Small Generator Interconnection Procedures (SGIP) and Small Generator Interconnection Agreement (SGIA).

The LGIP specifies that an Interconnection Request is in the form of Appendix 1 to the LGIP, and initiating an Interconnection Request includes a monetary deposit, demonstration of Site Control, and also a completed application in the form of Appendix 1. Further, Section 6.1 states that the Interconnection Customer must provide the “technical data called for in Appendix 1, Attachment A.”

Attachment A to Appendix 1 of the LGIP is the Large Generating Facility Data section of the Interconnection Request, and defines the technical data required for an Interconnection Request. For synchronous generators, the required technical information is fairly comprehensive and will provide a reasonable amount of information to inform and verify the dynamic models provided for those resources. However, for wind generators, the only information requested is shown in Figure 1.5 and there is no specified technical data for solar PV resources in the Attachment.

While it is understood that only limited technical detail may be known for the interconnecting resource during the Feasibility Study phase of interconnection, detailed modeling information should be available for stability studies per the System Impact Study phase of interconnection. Section 7 of the LGIP specifies this process and associated requirements. Section 7.1 states that if the “Interconnection Customer does not provide all such technical data when it delivers the Interconnection System Impact Study Agreement, [the] Transmission Provider shall notify the Interconnection Customer of the deficiency within five (5) Business Days of the receipt of the executed Interconnection System Study Agreement and Interconnection Customer shall cure the deficiency within ten (10) Business Days of receipt of the notice...” It is unclear whether this statement specifically applies to the modeling data needed to execute the study, in appropriate data format with sufficient technical detail. If it does cover the modeling data, these timelines are likely too tight for the Transmission Provider to do a thorough review of the dynamic models and their parameters and for the Interconnection Customer to engage necessary stakeholders (e.g., the inverter and plant-level controller manufacturers).

Section 24.3 of the pro forma LGIA states that the Interconnection Customer must provide updated information, including manufacturer information, no later than 180 days prior to Trial Operation. The section states:
“...Large Generating Facility data requirements contained in Appendix I to the LGIP...[and] it shall also include any additional information provided to the Transmission Provider for the Feasibility and Facilities Study. Information in this submission shall be the most current Large Generating Facility design or expected performance data. Information submitted for stability models shall be compatible with Transmission Provider standard models. If there is no compatible model, Interconnection Customer will work with a consultant mutually agreed to by the Parties to develop and supply a standard model and associated information.”

Section 24.3 also states that if the “data is materially different from what was originally provided to the Transmission Provider pursuant to the Interconnection Study Agreement...then Transmission Provider will conduct appropriate studies to determine the impact of Transmission Provider Transmission System based on the actual data submitted...The Interconnection Customer shall not begin Trial Operation until such studies are completed.”

While the process outlined here in Section 24.3 of the LGIA is relatively clear in terms of providing the most up-to-date information and models for stability studies, discussions within and between NERC and TPs and PCs have stressed the tight timelines and pressure from Transmission Provider management to expeditiously move the interconnection requests through the process for fear of complaints from Interconnection Customers regarding unfair requests. Entities have indicated that studies may not be revisited and fully vetted upon receiving updated dynamic modeling information. Further, TPs and PCs have stressed that the data supplied by the Interconnection Customer may not even be accurate or reflective of the actual performance of the resource until well past the interconnection process and after Commercial Operation. For example, the majority of dynamic models for BPS-connected solar PV resources did not accurately reflect momentary cessation and this finding was not widely known until after the NERC Alert process. TPs and PCs have stressed that they have limited authority to demand additional information during the interconnection process, and take the dynamic models and information provided by the Interconnection Customer as credible and accurate.

Per FERC Order 845, Transmission Providers must develop a technological change procedure to outline what technological changes would be permitted without re-study. If the technological changes are equal to or better than the existing technology, no re-study should be required according to FERC Order 845. The question raised is: “Who makes the determination that the technological advancement is equal to or better than the previous performance?” In many cases, changes to control settings, control features, etc. require detailed studies to ensure no unknown control interactions or anomalous behavior occurs from the resource during large disturbance events. It is unclear to TPs when they can require re-study due to models not being correct or accurate. Blanket determinations of what constitutes an acceptable change without sufficient study may put the BPS in potential situations of elevated reliability risk as the penetration of inverter-based resources continues to increase.

For the reasons stated in this section, it is recommended that the interconnection study procedures be reviewed and possibly improved to ensure clarity and consistency for inverter-based resources. Specifically, it should be made clear the types of data required to be provided during the Interconnection Request and throughout the entire study process, as well as when changes to equipment, controls, technology, settings, and other characteristics that could change the electrical response of the resource should be restudied.
Chapter 2: Reliability Studies of Inverter-Based Resources

NERC IRPTF developed a sub-group focusing on modeling and reliability studies in the Western Interconnection since the majority of grid disturbances have occurred in this region. The sub-group performed many system studies to understand potential reliability issues that may be attributed to different inverter-based resource performance issues. These studies, their findings, and recommendations based on the study results are provided in this chapter.

A range of studies were performed by IRPTF in phases as the industry continued to expand its knowledge and understanding of inverter performance during large disturbance events. These phases included the following:

- **Phase 1:** Phase 1 used a light winter base case that was adapted to represent minimum inertia and minimum reserves. This was considered by IRPTF study engineers to represent a heavily stressed, unrealistic operating case but was used as the worst case scenario from an inertia and reserves standpoint. The goal of this study was to review the Resource Loss Protection Criteria (RLPC) impacts caused by potential widespread MC. Phase 1 studies applied a user-written model, as described in the following section.

- **Phase 2:** Phase 2 used a light summer base case intended to represent a mid-day condition where CAISO is preparing for ramping later in the afternoon. This case included more online reserves in preparation for that ramp and was deemed more realistic from a dispatch perspective. The case was compared against real-time operating conditions and deemed suitable. Phase 2 studies applied the same user-written model described in Phase 1.

- **Phase 3:** Phase 3 studies used the same base case as Phase 2. If the actual MC settings were provided by the GO to the TP and PC per the NERC Alert following the Canyon 2 Fire disturbance, then the actual MC settings were updated in the dynamic models supplied by the GOs.

**Development of User-Written Model to Represent Momentary Cessation**

Data from the NERC Alert showed that the vast majority of BPS-connected solar PV inverters use MC during large voltage disturbances. However, IRPTF reviewed the WECC base cases and determined that few of the dynamic models used in the interconnection-wide base case accurately represent MC behavior. Therefore, IRPTF determined that the best modeling approach for the purposes of the Phase 1 and Phase 2 studies was to use the models supplied by the equipment owners and introduce a user-written model that interacts with the existing models to capture the MC. This decision was made to ensure consistency with the models submitted by the equipment owners (i.e., the GOs) while also ensuring the large disturbance behavior more accurately reflects the actual installed performance. The goal was to minimize, to the extent possible, any changes to the GO-supplied models while also enabling the ability for IRPTF to effectively study different assumptions for MC and its use across the BPS.

The user-defined model was developed to represent MC for BPS-connected solar PV resources. The model is invoked by a model entry in the dynamic model file, with the following MC parameters:

- **vblk** – MC low voltage threshold [pu]
- **delay** – recovery delay [s] once the voltage recovers above vblk
- **rrpwr** – active current ramp rate [pu/s] during the recovery period
- **lockout** – number of successive MC events before the inverters are permanently locked out

These parameters are applied by the user-defined model to all generators in the base case with a turbine type set to 31. For the purposes of this study, the model was configured such that any generator with the third owner value

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19 Ramping caused by the drop-off of solar PV resources in the late afternoon due to the sun setting.
20 Turbine type is a field provided in GE PSLF software to represent different types of generating resources in the powerflow base case. The WECC Base Case Preparation Manual requires all BPS-connected solar PV resources to be modeled using turbine type value set to 31.
set to 999 would be excluded from applying these MC controls. During initialization, the user-defined model saves
the list of generators applying the model.

At each simulation step, the user-defined model applied to each individual generator monitors for conditions that
trigger MC. A generator operates in one of the following modes:

- **Normal mode**: voltage is above $v_{blk}$ and the generator is not in recovery mode; the user-defined model does
  not apply any additional controls to the supplied models. All original parameters in the supplied models are
  in effect.

- **Block mode**: voltage is below $v_{blk}$; the user-defined model forces active and reactive current command to
  zero, and zero current is injected from the resource.

- **Delay mode**: voltage dropped below $v_{blk}$ and is now above $v_{blk}$ for less than delay seconds; the user-defined
  model continues forcing both active and reactive current command to zero (i.e., remaining in MC).

- **Recovery mode**: voltage dropped below $v_{blk}$ and is now above $v_{blk}$ for more than delay seconds and less
  than recovery period ($1/rrpwr$); the user-defined model replaces the active current ramp rate in the supplied
  models to $rrpwr$.

The user-defined model approach is suitable for these types of exploratory studies to understand different
assumptions on inverter behavior and their impacts to BPS performance (i.e., varying MC settings for voltage
threshold, delay, and ramp rate recovery). Application of the user-defined model is not suitable for production-level
reliability studies (i.e., establishing system operator limits, annual transmission planning assessments, and operations
planning assessments) since the user-defined model applies the same settings to all generators in which the model
is applied. Further, the model affects the performance of the GO-supplied models. In this case, it is believed that
these changes actually better-reflect the actual behavior of the resources; however, these models need to be updated
by the GO and supplied to the TP and PC for them to enter the interconnection-wide base cases.

**Phase 1: WECC Resource Loss Protection Criteria Assessment**

Initial analysis of the Blue Cut Fire disturbance identified MC as a widely used form of ride-through during large
disturbances on the BPS. The initial concern regarding the momentary loss of active power was frequency instability
and the potential triggering of underfrequency load shedding (UFLS). IRPTF performed stability studies and published
a report on this subject. The key takeaway was that frequency stability due to MC was not a significant issue
assuming a reasonable return to service behavior from inverter-based resources. However, it was also determined
that BPS transient stability could be affected if MC is widely applied across the BPS with certain settings. Based on
the limited data available at the time, it was determined that “typical” MC settings were as described in Table 2.1.
Preliminary studies were performed and the team determined that the combination of thresholds in Table 2.1 may
result in system instability if widely applied to solar PV resources connected to the BPS. At that point, the RLPC
assessment was complete but the focus turned toward assessing transient and voltage stability issues.

<table>
<thead>
<tr>
<th>Characteristic</th>
<th>Default Setting</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low Voltage Threshold</td>
<td>0.9 pu</td>
</tr>
<tr>
<td>Recovery Delay</td>
<td>0.5 s</td>
</tr>
<tr>
<td>Active Current Recovery Ramp Rate</td>
<td>1.0 pu/s</td>
</tr>
</tbody>
</table>

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**Phase 2: Initial WECC Stability Simulations**

A large instantaneous active power change in one part of the BPS will cause large changes to bus voltage angles and subsequent power swings across the BPS. This has conventionally been an issue with the loss of large synchronous generators or tie lines, and has been a relatively minor issue for normally cleared BPS faults. However, with solar PV resources utilizing MC, voltage depressions caused by BPS faults may result in widespread MC across a large geographical area. For bolted three-phase close-in faults, terminal voltage may drop to almost zero for local generators, causing even synchronous machine power output to be close to zero. However, for synchronous machines, this is a relatively local phenomenon, and resources on the BPS electrically farther away from the fault should be significantly less affected. IRPTF studies, on the other hand, showed that the “typical” MC settings applied to many BPS-connected solar PV resources could also invoke angular swings on the BPS and therefore needed closer examination. MC settings shown in Table 2.1 were applied since, at the time, no further information was available or easily applicable to the case dynamics data. These simulations are described here as Phase 2 studies.

**Extent of Possible Momentary Cessation**

Initial stability simulations explored the extent of BPS buses that could potentially have voltage low enough to elicit MC from solar PV resources during on-fault conditions. These studies used a normally-cleared (4 cycle), three-phase bolted fault on an EHV bus in Southern California. Figures 2.1 and 2.2 show the results plotted geographically. BPS buses across a large area of the Western Interconnection can experience voltage less than 0.9 pu during on-fault conditions (blue area of Figure 2.1). Conversely, very low voltage (e.g., less than 0.4 pu, as shown in the blue area of Figure 2.2) during on-fault conditions are only observable in a small geographic region around the fault. Thus, lowering the MC low voltage threshold exponentially decreases the risk of widespread MC and the potential risk of stability issues. Figures 2.1 and 2.2 illustrate the primary risk of BPS system instability is widespread use of MC with a relatively high value for the MC low voltage threshold. Eliminating the use of MC by inverter-based resources, in favor of providing dynamic reactive support (which is commonly available in modern inverter designs), significantly minimizes the risk of BPS instability issues.

![Figure 2.1: BPS Bus Voltages during On-Fault Conditions for Fault in Southern California](image)

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22 Typical assumption for TPL-001 stability simulations for P1 contingencies.
Identified Potential Instability Events

To identify fault locations that could result in instability or unacceptable system performance, normally-cleared three-phase bus faults were simulated near major 500 kV buses across the Western Interconnection. The MC settings shown in Table 2.1 were applied to all BPS-connected solar PV resources as a conservative assumption, based on the data available at the time of simulations. While varying levels of system performance were identified, only two potential instabilities were identified – an N-1 fault event and an N-1-1 fault event with no system redispatch between contingencies. These two simulations are described below to illustrate the analysis of the instability and identify key drivers of the instabilities.

**N-1 Fault Simulation**

A normally-cleared bolted three-phase fault was applied on a transmission circuit near a 500 kV bus in the PG&E footprint. The simulation results showed system instability caused by MC, which was attributed to lack of dynamic reactive support during and immediately following the fault. When the fault is applied, about 7,000 MW of solar PV resources across California and neighboring areas exhibit MC (see Figure 2.3). MC occurs instantaneously upon voltage falling below the MC threshold value (i.e., 0.9 pu), so this would occur for a normally-cleared fault. Upon fault clearing, voltages remained depressed below the MC voltage threshold in the Northern California region, and the inverters therefore did not return to pre-disturbance output (i.e., remained in MC after fault clearing). The lack of reactive power support in the area following fault clearing caused transient voltage collapse along a major transmission corridor within a couple seconds. Figure 2.3 also shows BPS bus voltage magnitudes in California, and shows the sustained low voltage after fault clearing prohibiting active and reactive current recovery of solar PV resources to pre-disturbance levels.
Widespread MC, resulting in the zero current injection from solar PV resources, removes a significant amount of reactive power support from these resources during and immediately following fault clearing. As BPS voltages begin to recover upon fault clearing, insufficient dynamic reactive power support is available to bring BPS bus voltages back to a stable operating point. This is primarily caused by the solar PV resources not resuming current injection following fault clearing because voltage remains below the MC low voltage threshold. This sequence of events occurs immediately upon fault clearing as a large power swing is picking up across the Western Interconnection due to the deficit of power in the California region. Voltages along the interties collapsed about 1 second after fault clearing. The primary driver of voltage collapse in this local region is the inability of solar PV resources to recover from MC due to reduction of reactive power support.23

During the N-1 contingency, interactions with widespread MC and HVDC circuit behavior played a critical role in BPS stability. Line commutated converter (LCC) HVDC circuits often have controls that will block thyristor firing when voltages fall below a pre-determined threshold.24 On the inverter end (in Southern California) of this HVDC circuit that threshold is around 0.9 pu ac voltage for a pre-defined period of time. Consider Figure 2.4 (left plot) showing the inverter-side ac bus voltage as well as the HVDC circuit power flow. Voltage falls below 0.9 pu due to the fault and remains depressed below this level due to the widespread MC of solar PV resources. This triggers thyristor blocking and power flow immediately being reduced to zero on the HVDC circuit. That power is transferred to the ac system and picked up across key ac transmission interties as seen in Figure 2.4 (right plot). The blocking of the HVDC circuit caused by widespread momentary cessation and insufficient reactive power support near the inverter-end of the HVDC terminal further exacerbates the ac system power swings and further drives voltage collapse along major ac circuits.

Voltages at the midpoint of this large power transfer (as shown in Figure 2.3) decay the fastest and collapse within 1.5 seconds after the fault. During the fast voltage decay in the first swing, synchronous generators within PG&E lose synchronism at about 0.5 second after the fault. Following PG&E, other synchronous generators in the Southern California area lose synchronism within 1.0 second after the fault.

Upon identifying this instability, the HVDC circuit controls were further studied. This HVDC circuit includes a RAS that trips a large amount of synchronous generation in the Pacific Northwest when flows exceed a pre-defined threshold. The RAS is designed to support BPS voltage stability for situations where major ac interties experience significant power swings that drive transient voltage performance issues (as described above). The RAS is event-driven (i.e., using line loss logic) for specific contingencies in the Pacific Northwest region, and was not designed for prolonged voltage depressions in the Southern California footprint causing sustained blocking of the HVDC circuit. Therefore, it

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23 Widespread MC also causes induction motor loads to slow down thereby drawing more reactive current from the system.
24 This is the expected performance of the HVDC circuit to protect from commutation failure, and is modeled accordingly in stability simulations.
was important to simulate this RAS in more detail (simulations above did not include the RAS action to trip generation) and understand its impacts on BPS performance with the HVDC circuit blocking and widespread MC.

Delayed voltage recovery lasting more than 1 second with voltage below the pre-determined threshold at the inverter-end (receiving-end) of the HVDC circuit caused the HVDC RAS to trigger generator tripping actions. About 2,000 MW of generation in the Pacific Northwest would be tripped by the RAS actions based on the ac and dc circuit flows in the base case. Generation tripping initiated by the RAS action reduced the large power swing on the ac interties (as expected) and stabilized the BPS for this N-1 contingency. Figure 2.5 shows HVDC and ac intertie flows with the RAS actions modeled.

![Figure 2.5: AC and DC Intertie Flows for N-1 Fault with RAS Modeled](image)

With the RAS modeled appropriately, bus voltage magnitudes along the ac interties recover to acceptable levels following fault clearing. Figure 2.6 (left) shows bus voltages with the RAS modeled (solid line) and within the RAS modeled (dashed line). Reactive power deficiency along the ac intertie in Northern California caused by solar PV MC still exists; however, the RAS action offloads the ac intertie and allows voltage to recover and solar PV resources to return to pre-disturbance output. However, bus frequencies fall close to UFLS levels, which is not intended for a normally-cleared N-1 contingency (see Figure 2.6, right). The combination of loss of solar PV resources due to MC and the generation tripped in the Pacific Northwest due to RAS action are the primary drivers for the large frequency excursion. In addition, the amount of generation lost exceeds BA requirements for this type of contingency, and could increase the operating reserve requirements if not mitigated.

![Figure 2.6: AC Intertie Bus Voltage with and without RAS (left) and System Frequency with RAS (right)](image)
One other instability was identified during the screening studies, which was an N-1-1 contingency with no system redispatch between contingencies. With one line taken out of service in the powerflow base case (first N-1), a high-penetration wind area in Southern California was radially connected to the grid via one 500 kV transmission circuit. A line fault on the 500 kV line was applied. The fault causes widespread MC from solar PV resources and the HVDC circuit to block (again initiating the Pacific Northwest RAS action). In addition, wind generation is consequentially tripped due to the permanent fault removing the plant’s only remaining grid tie to the BPS. Figure 2.7 shows the HVDC and ac intertie power flows, in addition to total BPS solar PV and wind power output. Figure 2.8 (left plot) shows BPS bus voltages along the ac intertie and Figure 2.8 (right plot) shows system frequency. While the system remains stable, performance is marginal and would not be deemed acceptable. Transient voltage swings along the ac intertie are severe and key bus voltages in that area are marginally stable (approaching the instability point). System bus frequencies fall to near or below the first stage of UFLS operations, which would also not be deemed acceptable BPS performance.

**Key Takeaway:**
Widespread use of MC from BPS-connected solar PV resources following a fault event in the Northern California region could interact with HVDC controls. This interaction could result in inadvertent operation of RAS actions that were not designed for this type of contingency. While the system remained stable for the simulated contingency and performance of the BPS-connected solar PV fleet, system performance was not acceptable. Therefore, IRPTF determined that the elimination of MC was needed to improve BPS stability performance now and into the future. These studies did not, however, identify a known stability issue since the default settings for MC were used rather than actual equipment settings (since this data was not available).

**N-1-1 Fault Simulation**

One other instability was identified during the screening studies, which was an N-1-1 contingency with no system redispatch between contingencies. With one line taken out of service in the powerflow base case (first N-1), a high-penetration wind area in Southern California was radially connected to the grid via one 500 kV transmission circuit. A line fault on the 500 kV line was applied. The fault causes widespread MC from solar PV resources and the HVDC circuit to block (again initiating the Pacific Northwest RAS action). In addition, wind generation is consequentially tripped due to the permanent fault removing the plant’s only remaining grid tie to the BPS. Figure 2.7 shows the HVDC and ac intertie power flows, in addition to total BPS solar PV and wind power output. Figure 2.8 (left plot) shows BPS bus voltages along the ac intertie and Figure 2.8 (right plot) shows system frequency. While the system remains stable, performance is marginal and would not be deemed acceptable. Transient voltage swings along the ac intertie are severe and key bus voltages in that area are marginally stable (approaching the instability point). System bus frequencies fall to near or below the first stage of UFLS operations, which would also not be deemed acceptable BPS performance.

**Figure 2.7: Total Solar PV and Wind Output and Intertie Flows for N-1-1 Fault (with RAS Action)**

**Figure 2.8: BPS Bus Voltages (left) and System Frequency (right) for N-1-1 Contingency (with RAS Action)**

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25 “Consequentially tripped”, in this case, refers to the wind plant being removed from service upon the permanent fault being cleared by protective relaying. With only a single radial connection to the BPS, this is the expected contingency definition.
Mitigation of Potential Instability Conditions
With the two instability cases identified, IRPTF studies focused on high-level considerations for the various solutions that could be employed to address the instabilities observed. The goal of this exercise was to understand the extent to which these solutions could mitigate the potential instability cases caused by the widespread use of MC. Table 2.2 shows an overview of the considerations explored by IRPTF, which are based partly on simulation results and partly on engineering judgment from the IRPTF study team. The most effective solution option included eliminating MC to the extent possible. Obviously, completely eliminating MC will correct the problem; however, marginal improvements to MC settings and partially eliminating MC also greatly improves BPS performance. Refer to the Phase 3 studies described below for more details.

<table>
<thead>
<tr>
<th>Mitigation Option</th>
<th>Instability Mitigated</th>
<th>Acceptable BPS Performance</th>
<th>Discussion</th>
</tr>
</thead>
<tbody>
<tr>
<td>Eliminate MC</td>
<td>Yes</td>
<td>Yes</td>
<td>Eliminating MC greatly improves BPS performance including angular, voltage, and frequency stability. Interaction with HVDC controls and RAS are eliminated. All alternative options for inverter controls provided adequate BPS performance (P-priority had local performance issues (see Chapter 3)).</td>
</tr>
<tr>
<td>Operating Limit Restrictions</td>
<td>Yes</td>
<td>Yes</td>
<td>Stability issues are mitigated if operating limits are restricted; no operation of RAS if ac and dc intertie flows are limited; MC still causes adverse impacts on system performance, although performance requirements are met; costly solution with economic impacts of curtailment.</td>
</tr>
<tr>
<td>Reactive Power Support</td>
<td>Marginal</td>
<td>Marginal</td>
<td>Multiple STATCOM locations were explored; a significantly large amount of reactive power is needed to mitigate transient voltage collapse along corridor and depressed voltage at inverter-end of HVDC circuit; ineffective solution for this specific problem.</td>
</tr>
<tr>
<td>Additional RAS Actions</td>
<td>Unlikely</td>
<td>Unlikely</td>
<td>The only additional RAS action suitable to address this issue would be load tripping in Southern California, which is not an acceptable solution for N-1 contingency events. This solution would have significant economic impacts and load service degradation.</td>
</tr>
<tr>
<td>Transmission Reinforcement</td>
<td>Likely</td>
<td>Possibly</td>
<td>Significant EHV network improvements needed to eliminate need for RAS; extremely costly solution option, and likely not possible due to permitting, expense, and regulations; not recommended.</td>
</tr>
</tbody>
</table>

Phase 3: Detailed Stability Studies using NERC Alert Data
As described in Chapter 1, the NERC Alert following the Canyon 2 Fire disturbance gathered detailed information regarding MC from currently installed BES solar PV resources. The NERC Alert recommended GOs to provide updated dynamic models that reflect the actual installed equipment in the field (since the currently submitted models in the interconnection-wide base cases were widely deemed to not match actual inverter settings). The NERC Alert also recommended that GOs review their inverter capabilities and determine if MC could be eliminated, and to submit updated dynamic models to their TP and PC for study prior to material changes being made to installed equipment.

26 Instability could be mitigated through generation redispatch by bringing 500 MW of generation on-line in the PG&E area near the ac intertie, and reducing 500 MW of generation in the Pacific Northwest. The system remains stable; however, transient performance is marginal, with a severe voltage dip during the first swing. Any use of system redispatch as a preventive measure should include extensive, detailed studies under various system operating conditions to define the stability boundary in terms of path flows and generation dispatch.
Since most of the models provided by GOs following the NERC Alert were either not usable or did not match the data provided in the NERC Alert, the IRPTF study team updated the dynamic models manually to more accurately reflect the expected performance for existing inverter-based resources. IRPTF study team used the information provided from the NERC Alert process to update the models and then perform the same simulations that were performed in Phase 2 studies. The goal of Phase 3 studies was to understand the BPS performance based on dynamic models that more closely resemble actual installed equipment. The results from these simulations are provided in this section.

Studies using Existing and Proposed Momentary Cessation Settings

As mentioned, the dynamic models were updated by TPs and PCs on the IRPTF study team to reflect the data provided following the NERC Alert. A flowchart of the updates to the dynamic models for solar PV resources is shown in Figure 2.9. About 14,500 MW of BPS-connected solar PV resources are represented in the WECC base case. GOs representing approximately 7,200 MW submitted data during the NERC Alert process. Of the remaining 7,300 MW of solar PV resources that did not submit data as part of the NERC Alert, the default MC settings from Table 2.1 were assumed (and updated in the dynamic data file) as a conservative yet reasonable assumption. For those resources that submitted data, about 6,000 MW stated they use MC and their dynamics data was updated accordingly. For the remaining 1,200 MW of solar PV resources stating they do not use MC, their dynamics data was left unchanged from what is currently used in the WECC base case.

27 As described in Chapter 1, the models received by the TPs and PCs from the GOs owning solar PV resources were largely unusable and inaccurate (i.e., did not match the information supplied in the NERC Alert).

28 While entities owning non-BES resources were requested to provide data, only BES resources are required to respond to the data requests in the NERC Alert. This explains why modeling assumptions were made on roughly half of the solar PV resources in the WECC base case.
The NERC Alert following the Canyon 2 Fire disturbance also requested GOs owning BPS-connected solar PV facilities to identify possible improvements to controls to eliminate MC, to the extent possible. In situations where it could not be eliminated, modifications to control settings were recommended (where possible). As stated in Chapter 1, very few dynamic models were provided by GOs regarding proposed improvements to inverter performance during large disturbances. Therefore, again, the IRPTF study team used the NERC Alert data provided by GOs to update the dynamic models to reflect the proposed changes. Figure 2.10 shows a flowchart of the data collected from the NERC Alert, and the ways it was used to model the proposed settings. Of the nearly 6,000 MW of resource that currently use MC, about 3,250 MW stated that they could eliminate its use while 2,700 MW stated they could not. If settings could be changed to eliminate MC, the original dynamics data file records were used (which do not model MC). Where MC could not be eliminated, the settings were updated manually by the IRPTF study engineers to reflect the current or proposed changes to MC settings provided in the NERC Alert data.

With the updated settings modeled, a comparative analysis was performed between the current settings and proposed settings based on the information collected in the NERC Alert and the process described above. Table 2.3 compares performance among different MC settings without simulating the RAS action versus simulating the RAS actions. With the current or proposed MC settings, the system is stable even without RAS action with frequency remaining above the UFLS threshold. The duration of the HVDC circuit blocking is shortened using the proposed MC settings; however, HVDC RAS would still be triggered in all simulations (which is not desirable for these contingencies). With the RAS actions modeled appropriately, the system is also stable with the frequency nadir reaching 59.6 Hz and 59.71 Hz for current MC and proposed MC settings, respectively. The UFLS threshold is generally 59.5 Hz for the Western Interconnection.

<table>
<thead>
<tr>
<th>System Response</th>
<th>Default MC</th>
<th>Current MC</th>
<th>Proposed MC</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>RAS Actions Not Modeled</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Initial HVDC blocking duration [s]</td>
<td>0.93</td>
<td>0.90</td>
<td>0.84</td>
</tr>
<tr>
<td>Successive HVDC Blocking</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>System Stable</td>
<td>No</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>System Frequency Nadir [Hz]</td>
<td>N/A (Unstable)</td>
<td>59.63 Hz</td>
<td>59.78 Hz</td>
</tr>
<tr>
<td><strong>RAS Actions Modeled</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Successive HVDC Blocking</td>
<td>No</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>System Stable</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
</tr>
</tbody>
</table>

Figure 2.10: Flowchart of Proposed MC Settings

MW stated they could not. If settings could be changed to eliminate MC, the original dynamics data file records were used (which do not model MC). Where MC could not be eliminated, the settings were updated manually by the IRPTF study engineers to reflect the current or proposed changes to MC settings provided in the NERC Alert data.
For the N-1-1 contingency, the system is still unstable using the MC settings for currently installed solar PV resources without the RAS modeled. With the RAS modeled, all MC settings are stable; however, the frequency nadir remains above the first stage of UFLS operation only for the proposed MC settings. Unintended load shedding may be caused by the combination of generation tripping from RAS action, MC from BPS-connected solar PV resources, and consequential tripping of wind generation due to the contingency. This scenario would likely require a system operating limit or other curtailment to the wind facility to mitigate the potential for unacceptable BPS performance for this N-1-1 contingency.

| System Frequency Nadir [Hz] | 59.52 | 59.6 | 59.71 |

Table 2.4: Performance Comparison for Different MC Settings for N-1-1 Contingency (without and with RAS Action)

<table>
<thead>
<tr>
<th>System Response</th>
<th>Default MC</th>
<th>Current MC</th>
<th>Proposed MC</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>RAS Actions Not Modeled</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Successive HVDC Blocking</td>
<td>Yes</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>System Stable</td>
<td>No</td>
<td>No</td>
<td>Yes</td>
</tr>
<tr>
<td>System Frequency Nadir [Hz]</td>
<td>N/A (Unstable)</td>
<td>N/A (Unstable)</td>
<td>59.76</td>
</tr>
<tr>
<td><strong>RAS Actions Modeled</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Successive HVDC Blocking</td>
<td>No</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>System Stable</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>System Frequency Nadir [Hz]</td>
<td>59.39</td>
<td>59.47</td>
<td>59.59</td>
</tr>
</tbody>
</table>

Figure 2.11 (left) shows a noticeable improvement to the amount of solar PV resources entering MC when the proposed MC settings are applied; however, it is still observable that about 5,000 MW of solar PV resources enter into MC. Figure 2.11 (right) shows system frequency for the different MC settings.

![Figure 2.11: Total Solar PV Output (left) and System Frequency (right) for N-1-1 with RAS](image)

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29 This is predominantly caused by the lack of data for non-BES solar PV resources. So the assumption was made that those resources use the default MC settings used in previous studies, as a conservative assumption.
Impacts to Key Protection Systems

Due to the large power swings induced on the BPS caused by large amounts of BPS-connected solar PV resources entering momentary cessation, the IRPTF study team focused on including relay models on some of the ac major interties across the Western Interconnection to ensure this performance did not adversely impact BPS protection system operations. In particular, the farthest reaching forward distance elements and out-of-step (OOS) relaying on one of the key ac interties was of primary interest since this was identified as one location where transient voltage collapses could occur in some of the study scenarios. Load encroachment blinders were included to show where the distance elements would be blocked. Figures 2.12 and 2.13 show the OOS and distance elements on one of the key transmission circuits on one of the ac interties, respectively. These impedance trajectories are plotted for instructional purposes only; these plots do not provide the complete picture for relay response to large power swings.30 Relay operation is much more complex and is ultimately determined by additional items such as the impedance rate of change, time delay, frequency, minimum current threshold, and communications from the remote end. In both the N-1 and N-1-1 scenarios, the apparent impedances are outside of the OOS blinders, and are therefore unlikely to cause an OOS trip. The apparent impedances enter the zone 3 quad element, but are blocked by load encroachment. No other distance element zones were entered. Therefore, it is unlikely that either scenario would cause a trip of the protection systems on this major ac intertie.

Figure 2.12: OOS Characteristic for 500 kV Line Swing Impedance

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30 The best way to determine how a relay will respond is to test the relays on a hardware in the loop test bench using simulated events created from system models. This would require bus voltage magnitude (volts), voltage magnitude (volts), bus voltage angle (deg or rad), line current magnitude (A-rms), line real three phase power (MW), line reactive three phase power (Mvar), and bus frequency (Hz).
For severe contingencies with conservative assumptions for MC settings for solar PV resources that did not provide NERC Alert data, the apparent impedance swings still do not enter any zone of protection to cause potential tripping for one of the major ac interties most affected by the large power swings. In addition, information regarding BPS protection system settings were not readily available in the dynamic models and require engagement between protection engineering and transmission planning engineering departments across multiple organizations. This type of engagement is likely not occurring on a broad scale for standard TPL planning assessments. Relay information, and at least high-level relay models, should be available to transmission planners when performing system stability studies. While actual installed protection is likely much more complex, standard protection models working in “monitoring mode” could help inform planners to any potential trips. Incorporating these types of protection models into stability simulations and the interconnection-wide base cases should continue to be a priority for industry moving forward. Training may also be needed to enable planning engineers to properly interpret the “monitoring mode” results.

Current Control Sensitives if Eliminating Momentary Cessation

With the IRPTF recommendation to eliminate MC for BPS-connected solar PV resources, the IRPTF study team focused on the various types of inverter controls during ride-through operation that could impact BPS stability both locally and on a wide-area basis. The current injection from these resources during and immediately following BPS fault events were analyzed to understand the sensitivities that different control strategies may have on BPS performance. Inverters were assumed to continue current injection during low voltage conditions (rather than use MC), and sensitivities focused on active current priority (Ip priority) or reactive current priority (Iq priority).31 A combined Ip-Iq priority was also studied where Ip and Iq priorities adapt to terminal voltage conditions, entering Iq priority when voltage falls below 0.9 pu and remaining in Ip priority otherwise. Table 2.5 shows a comparison of inverter control strategies tested.

<table>
<thead>
<tr>
<th>Inverter Control Strategy</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>P-Priority</td>
<td>Preset all PQflag to P priority</td>
</tr>
<tr>
<td>Q-Priority</td>
<td>Preset all PQflag to Q priority</td>
</tr>
<tr>
<td>Q-0.9</td>
<td>Q-priority if voltage &lt; 0.9; original PQflag if voltage ≥ 0.9</td>
</tr>
<tr>
<td>P-Q-0.9</td>
<td>Preset all PQflag to P priority; Q priority when voltage &lt; 0.9</td>
</tr>
</tbody>
</table>

31 Note that these active and reactive prioritizations are only in effect once the inverter has reached its maximum current output (Imax). If the inverter is not limited by Imax, the inverter controls will seek to provide the commanded Ip and Iq necessary based on the programmed controls in the inverter. Therefore, Ip and Iq priority are only applicable for large disturbance behavior of inverter-based resources located close to the fault condition. Ip and Iq priority are also often referred to as “Q priority” and “P priority”, respectively.

32 Done through additional EPCL scripting language in GE PSLF.

33 Done through additional EPCL scripting language in GE PSLF.
System-wide stability and acceptable dynamic performance is maintained in all of the cases studied. The only notable difference between simulation results, on a wide-area basis, is the reduction of total solar PV output using Ip priority (see Figure 2.14). This is due to one solar PV plant tripping due to sustained low voltage. In that case, the solar PV resource does not contribute sufficient reactive power output during and immediately following the fault event, and enters a sustained low voltage condition causing tripping. During and immediately after a BPS fault, the injection of reactive current from all resources helps support and raise voltage to pre-disturbance levels. The higher voltage results in more available active current injection from the inverter-based resource. Thus, reactive current priority also helps raise the level of active power output from inverter-based resources during the fault. Therefore, based on the simulations performed, the IRPTF study team believes that Iq priority is the preferred inverter control strategy due to the ability to support BPS voltage during and immediately after the fault, which enables active current from inverter-based resources to quickly and reliably return to pre-disturbance levels. Detailed system studies may identify in some regions that Ip priority may be the preferred strategy; however, simulation results should be used to provide a technical basis for this decision.

Figure 2.14: Total Solar PV Active and Reactive Power Output for Ip and Iq Control Strategies

To obtain further insight into the application of Ip and Iq settings at an individual plant level, the performance of a 250 MW solar PV plant was examined with different Ip and Iq strategies and control settings. A few different scenarios were devised to study the performance of the different controls to different types of BPS contingencies and operating conditions.

- **Scenario 1:** A fault on a 500kV transmission circuit causes inverter terminal voltage to drop to 0.50 pu. Figures 2.15 to 2.17 show the performance under Ip priority, Iq priority with voltage control disabled, and Iq priority with voltage control enabled, respectively.
  - **Results:** Iq priority with voltage control enabled provides the optimal control strategy tested, avoiding degradation in on-fault voltage drop and post-voltage transient overvoltage conditions.
    - With Ip priority, a slight degradation in on-fault and post-fault voltage recovery is observed. Ip takes priority and limits the available Iq during the fault. This results in a slower voltage recovery as well as recovery of active power due to inverter controls.
    - With Iq priority with Imax equal to 1.3 and dynamic voltage control disabled, post-fault overvoltage is observed. Plant-level voltage control and local coordinated Q/V control is applied, which is dominated by the Kvi parameter equal to 40. Iq command rises to 1.3 pu during the fault. Ip command drops as Iq command ramps up to attempt to provide reactive support. Kqv is disabled and Vdip and Vup are -99 and 99, respectively. Hence, there is a slower response characteristic.

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34 Some reactive power is provided; however, voltage remains below 0.8 pu for a sustained period which causes the resource to trip.
With Iq priority and dynamic voltage control enabled (Kqv equal to 2), there is no observed post-fault voltage overshoot. The Kqv control loop has fast proportional gain response to clamp voltage down in response to the change in Iqcmd. Kqv set to 2 prevents overshoot since Iq command only rises to 0.5 pu during the fault. Ip command is only slightly clamped since voltage drop is not drastic. Fast recovery in active power occurs since Ip command is able to quickly respond and provide additional voltage support.

- **Scenario 2**: Nearby fault causes the inverter terminal voltage to drop to 0.2 pu. Figures 2.18 to 2.20 show the performance under Ip priority, Iq priority with voltage control disabled, and Iq priority with voltage control enabled, respectively.

  - **Results**: Same as described above, Iq priority with voltage control enabled provides the optimal control strategy tested, avoiding degradation in on-fault voltage and post-voltage transient overvoltage.
    - With Ip priority, again a slower voltage recovery is observed. During the fault, Ip command is clamped to Imax and Iq command is limited to 0. Upon fault clearing, controls respond to return active and reactive power to pre-disturbance levels.
    - With Iq priority, again an ac overvoltage occurs after the fault is cleared. The Kvi parameter of 40 and plant controls drive this behavior. Iq command rises quickly to 1.3 pu during the on-fault conditions. After the fault, 1.2 pu voltage is observed. The slower plant-level controls seek to slowly return voltage to acceptable levels about 130 ms after fault clearing.
    - With Iq priority and dynamic voltage control enabled (Kqv equal to 2), again the ac overvoltage is mitigated due to the fast inverter-level controls being able to bring voltage down immediately upon fault clearing. Ip command is only slightly clamped during the fault and not impacted upon fault clearing. Plant active power returns to pre-disturbance levels very quickly.

These sensitivity studies illustrate how the voltage control parameters can be adjusted and coordinated to achieve the desired performance. Multiple control parameters can be tuned, and different combinations of these parameters can all meet the performance requirement under one specific condition. Tuning parameters under as many scenarios as possible is necessary. Performance also depends on the interaction with the system itself. The same inverters installed at a different location would need to be tuned differently. It is critical that the dynamic models used to represent BPS-connected resources actually reflect the installed equipment in the field and are provided to the TP and PC during the interconnection studies process as well as during interconnection-wide case creation processes.

**Key Takeaway:**
Dynamic models used to represent BPS-connected resources should accurately reflect the installed equipment in the field and should be provided to the TP and PC during the interconnection studies process as well as during interconnection-wide case creation processes.
Figure 2.1: Ip-Priority with $I_{\text{max}} = 1.3$, $K_{qv}$ disabled

Degradation of $V$ as $I_p$ takes priority over $I_q$
Slower recovery in $P$ due to inverter controls and recovery of $V$

Figure 2.2: Iq-Priority with $I_{\text{max}} = 1.3$, $K_{qv}$ disabled

Post-fault overvoltage. Plant level $V$ control & local coordinated $QV$ control, dominated by $kv_l = 40$, $I_{q\text{cmd}}$ rises to 1.3 during fault. $I_{q\text{cmd}}$ ramps up to provide reactive support. This is from $V_{\text{ref}}$ parameter, with $K_{qv}$ disabled and $V_{d\text{ip}}=0.9$ and $V_{up}=99$. Hence, slower type response.

Figure 2.3: Iq-Priority with $I_{\text{max}} = 1.3$, $V_{d\text{ip}}=0.9$, $K_{qv}=2$

No post-fault overvoltage. $K_{qv}$ loop has fast proportional gain response to clamp voltage down by responding quickly with change in $I_{q\text{cmd}}$. $K_{qv}=2$ preventing overshoot since $I_{q\text{cmd}}$ only rises to 0.5 during fault. $I_{q\text{cmd}}$ able to rise, and only slightly clamped since voltage drop is not all that severe. Fast recovery in $P_g$ since $I_{q\text{cmd}}$ able to quickly respond and provide additional voltage support.
Figure 2.4: I_p-Priority with I_{max} = 1.3, K_{qv} disabled

Figure 2.5: I_q-Priority with I_{max} = 1.3, K_{qv} disabled

Figure 2.6: I_q-Priority with I_{max} = 1.3, V_{dip}=0.9, K_{qv}=2

No post-fault overvoltage. K_{qv} loop has fast proportional gain response to clamp voltage down by responding quickly with change in I_{qcmd}. I_{qcmd} only rises to 0.5 during fault. I_{qcmd} able to rise, and only slightly clamped since voltage drop is not all that severe. Fast recovery in P_{g} since I_{qcmd} able to quickly respond and provide additional voltage support.
Appendix A: Key Findings and Recommendations

Table A.1 provides the key findings and recommendations documented in this report related to BPS-connected inverter-based resource modeling and studies. These key findings and recommendations cover the following areas:

- Analysis of the NERC Alert data and industry follow-up activities
- Simulations and studies performed by the IRPTF of Western Interconnection dynamic performance
- IRPTF modeling work and technical discussions

Table A.1 is separated into three sections to mirror these three topic areas. Items A1–A6 focus on NERC Alert findings, items S1–S6 are associated with IRPTF studies, and items D1–D7 are based on technical discussions and industry work related to dynamic modeling needs.

<table>
<thead>
<tr>
<th>#</th>
<th>Key Findings and Recommendations</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>From NERC Alert Analysis...</td>
</tr>
</tbody>
</table>
| A1 | **Key Finding:** A significant number of inverter-based resources, particularly solar PV resources, have submitted RMS positive sequence dynamic models for the interconnection-wide case creation process (i.e., MOD-032-1) that do not accurately represent the control settings programmed into the inverters installed in the field. This was identified due to discrepancies between NERC Alert data and the dynamic models used in the interconnection-wide base cases.  
**Recommendation:** The interconnection-wide base case models used for planning assessments should be updated as quickly as possible to accurately reflect the large disturbance behavior of BPS-connected solar PV resources. This applies to Bulk Electric System (BES) resources as well as non-BES resources connected to the BPS. |
| A2 | **Key Finding:** Many of the updated dynamic models submitted during the NERC Alert, intended to represent the existing settings and controls currently installed in the field, either did not match the data provided by the GO for actual settings or did not meet TP and PC requirements for model performance (e.g., incorrect models used, incorrect parameters, or inability of model to initialize).  
**Recommendation:** TPs and PCs should proactively work with all BPS-connected solar PV resources connected to their system to ensure that the dynamic models correctly represent the large disturbance behavior of the actual installed equipment. This involves verifying the dynamic model parameters with actual equipment and control settings and should not be simply a cursory review of the models provided. |
| A3 | **Key Finding:** A significant number of GOs submitted NERC Alert data stating they could eliminate the use of MC for existing resources; however, either no model of proposed changes was provided or the provided model did not meet TP and PC requirements for model performance.  
**Recommendation:** TPs and PCs should proactively work with all GOs of BPS-connected solar PV resources in their footprint to review the NERC Alert data provided, develop an updated dynamic model of the proposed changes that can be made to eliminate momentary cessation, study the impacts of making this change to controls, and provide recommendations to the GO to make appropriate changes based on the study results. |

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35 A significant number of resources stated that they utilize momentary cessation (MC) for disturbance ride-through, yet the models provided showed current injection behavior during the same large disturbance operating mode.
### Table A.1: Key Findings and Recommendations from IRPTF Modeling and Studies Work

<table>
<thead>
<tr>
<th>#</th>
<th>Key Findings and Recommendations</th>
</tr>
</thead>
</table>
| A4 | **Key Finding:** GOs responded to the NERC Alert by providing the requested data and information about their facilities; however, very few GOs provided acceptable dynamic models that matched the data provided. Some TPs and PCs are proactive seeking corrections to these deficiencies but these activities are occurring outside the NERC Alert process. The NERC Alert itself did not remedy the issues associated with inaccurate dynamic model representation of BPS-connected inverter-based resources.  

**Recommendation:** If additional actions are needed to address the systemic models issues identified during the NERC Alert process, then another method of engaging or requiring industry to make these changes to the dynamic models will need to be implemented. |
| A5 | **Key Finding:** TPs and PCs are still becoming familiar with the relatively new dynamic models for inverter-based resources. These models are significantly more complex than synchronous generator dynamic models and documentation on their parameterization and correct utilization is limited. For this reason, experience has shown that many TPs and PCs are not familiar with how to perform suitable reasonability tests during model submittal processes (either during the interconnection process or during MOD-032-1 data reporting). Currently limited material is available and often requires expert input. In-house expertise on these models is fairly limited within many TP and PC engineering staffs. This allows either incorrect or inappropriate dynamic models to enter the interconnection-wide base cases.  

**Recommendation:** Industry should develop adequate technical guidance and reference materials on how to parameterize the RMS positive sequence dynamic models for BPS-connected inverter-based resources. Training should be provided to planning engineers to educate them on the structure and parameterization of these models for use in planning and operations reliability studies. |
| A6 | **Key Finding:** The NERC MOD-032-1 standard does not prescribe the details that the modeling requirements must cover; rather, the standard requirements leave the level of detail and data formats up to each TP and PC to define. Many TPs and PCs have developed detailed data requirements; however, little validation of the data provided by GOs is performed. In many cases, “usability testing” is performed that covers model initialization, data format correctness, and numerical robustness during simulated disturbance events. Assessments on the accuracy or reasonableness of the parameter values are not typically performed. Standardized validity testing for dynamic models of newer generation inverter-based resources are not readily available to TPs and PCs; this is a contributor to inaccuracies in the interconnection-wide base cases. While some entities have leveraged the capability of identifying “technical concerns” with data submittals per MOD-032-1 Requirement R3, experience has shown that entities are not utilizing this capability suitably nor following up with these requests with regional compliance groups when data continues to not meet requirements.  

**Recommendation:** Industry needs to more proactively review the dynamic models for model accuracy and address any technical concerns identified in a timely manner. These activities can help improve the interconnection-wide planning case quality. |
| From IRPTF Studies... |

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36 MOD-032-1 requires each TP and PC to jointly develop data requirements and reporting procedures for the collection of modeling data used in planning studies.
<table>
<thead>
<tr>
<th>#</th>
<th>Key Findings and Recommendations</th>
</tr>
</thead>
</table>
| S1 | **Key Finding:** Early stability studies using assumptions regarding the use of MC based on data provided from the first NERC Alert illustrated that widespread use of MC could cause system instability issues for N-1 contingencies if not mitigated. Momentary cessation at high voltage thresholds caused lack of reactive power support in key voltage-sensitive areas and resulted in large power swings across the BPS in the Western Interconnection. Further, the MC actions interacted with existing HVDC controls and RAS actions in the Pacific Northwest.  
**Recommendation:** These findings served as the technical justification that MC should be disallowed for newly interconnecting BPS-connected solar PV resources and should be eliminated to the extent possible for existing resources. Industry should be taking actions to eliminate the use of MC for existing resources, to the extent possible, and TOs should update their interconnection requirements to disallow its use for newly interconnecting resources. |
| S2 | **Key Finding:** More detailed studies using models modified to reflect the actual MC settings of BPS-connected solar PV resources (when data was available) following the Canyon 2 Fire disturbance NERC Alert showed that the BPS remains stable for the aforementioned contingencies. However, BPS performance is degraded by the use of MC, particularly when the recovery from MC is delayed or the recovery ramp rate is slowed. Elimination of MC or improvements to the MC voltage threshold or recovery characteristic had the greatest impact on improving BPS performance. Interactions with HVDC controls were still present, and the combination of solar PV MC, RAS actions due to HVDC controls, and consequential loss of additional active power due to certain fault events resulted in frequencies falling close to or below underfrequency load shedding (UFLS) thresholds.  
**Recommendation:** See S1 recommendation. |
| S3 | **Key Finding:** Solution options to mitigate poor BPS performance for widespread MC were explored, and it was determined that none of the system-level solutions (e.g., transmission reinforcement, widespread use of transmission-connected reactive devices, curtailment) proved to be an effective means of ensuring reliability. The best solution to the widespread use of MC to improve BPS performance was to eliminate its use to the extent possible.  
**Recommendation:** See S1 recommendation. |
| S4 | **Key Finding:** User-defined models were used to modify the dynamics model data provided by the GOs for the interconnection-wide base cases. These models updated the simulated response of those resources who were identified as using MC per the NERC Alert data, to more accurately capture their large disturbance behavior. The use of these user-defined models was necessary, since the majority of BPS-connected solar PV models in the interconnection-wide base case, provided by the GOs, were either the wrong model or were not parameterized to accurately reflect the large disturbance behavior of the actual installed resources. These user-defined models are not intended as a long-term solution nor should they be used in planning assessments. They were used in IRPTF studies as a workaround to widespread modeling deficiencies in the planning base cases. The interconnection-wide base cases need to be updated as quickly as possible with accurate dynamic models to ensure reliability studies are able to identify potential reliability issues.  
**Recommendation:** See S1 recommendation. |

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37 If reliability studies demonstrate that performance of the BPS-connected inverter-based resource is improved using MC for very low inverter terminal voltages, then the TP and PC (in coordination with the TO) should consider allowing its use on a case-by-case basis.

38 The NERC Alert gathered information regarding MC from about half of the BPS-connected solar PV resources. Conservative modeling assumptions regarding MC were used for the remaining resources.

39 This finding on acceptable performance should not degrade the criticality of getting the dynamic modeling issues addressed in a timely manner.
### Key Findings and Recommendations from IRPTF Modeling and Studies Work

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<tr>
<th>#</th>
<th>Key Findings and Recommendations</th>
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</table>
| S5 | **Key Finding:** With the recommendation to eliminate MC to the extent possible, the next question raised was which large disturbance operating mode provides the best BPS performance. All forms of active and reactive current priority for current injection during large disturbances provide better BPS performance than MC; however, reactive current priority with voltage control enabled provides the most optimal form of ride-through performance based on the sensitivity studies performed. Timely recovery and control of inverter voltage allows active current to resume to pre-disturbance output immediately following a severe fault event without causing overvoltage or delays in response.  

**Recommendation:** The controls and dynamic response of BPS-connected inverter-based resources should be tuned to meet BPS reliability criteria and support the BPS during normal operation and during contingency events. The dynamic models representing these resources should be updated to reflect the specific control settings and parameters. Refer to NERC Reliability Guideline: BPS-Connected Inverter-Based Resource Performance for details on recommended performance. |
| S6 | **Key Finding:** Protection system models were not widely available in the planning models, and therefore it was a challenge to study whether the large power swings caused by MC and other inverter behavior were having a potential impact on BPS protection system operation. Concerted efforts were taken to model key transmission paths; however, these models were not readily available to transmission planning engineers.  

**Recommendation:** Reasonable representation of protection systems should be included in the interconnection-wide base cases. The models used to represent these protection systems can be used in “monitor only” mode to flag potential operation of protection systems. More detailed analyses should be performed to identify any potential inadvertent operation of protection systems during contingency events. |

**From Ongoing IRPTF Discussions and Technical Analysis...**

| D1 | **Key Finding:** NERC MOD-026-1 and MOD-027-1 verification and testing activities do not adequately verify the accuracy of the dynamic models relative to actual installed equipment performance for large disturbance response. Small disturbance testing does not capture the large disturbance behavior of inverter-based resources and therefore does not verify dynamic model parameter values. This issue may be a contributor to the systemic modeling challenges of accurately modeling BPS-connected solar PV resources in planning studies.  

**Recommendation:** IRPTF performed a detailed review of the NERC Reliability Standards and identified MOD-026-1 and MOD-027-1 as needing revisions to more accurately serve the intent of the standard for BPS-connected inverter-based resources. Changes should ensure that large disturbance behavior of inverter-based resources is verified. Verification activities beyond matching simulated response with actual response to a small disturbance test should be a mandatory step in the model verification process. This is implicit in MOD-026-1 and MOD-027-1 and should be made an explicit step. TPs and PCs should be required to verify the appropriateness of all dynamic model parameters to ensure suitability of these parameters to match actual performance for all operating conditions. This may include verification of inverter-level and plant-level controller settings, OEM specification sheets, etc. |

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41 For example, a GO could submit a REEC_B dynamic model that has no capability to represent MC. And small disturbance verification testing could identify a suitable dynamic model match between simulated and actual response during testing. However, the tests in no way test the large disturbance behavior. Therefore, there is no comparison of actual response and modeled response for large disturbance response.
## Table A.1: Key Findings and Recommendations from IRPTF Modeling and Studies Work

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<tr>
<th>#</th>
<th>Key Findings and Recommendations</th>
</tr>
</thead>
</table>
| D2 | **Key Finding:** A disconnect exists in transferring knowledge about actual controls installed in the field and how they are accurately parameterized in the dynamic models provided to TPs and PCs. This issue appears to stem partly from the inverter manufacturers and consultants who prepare the dynamic models of their equipment and submit those models to the GOs. For example, inverter manufacturers stated that they were not aware of the issues with reec_b not accurately representing MC and recovery of current injection for large disturbance events. This model has been widely used by industry under the assumption that it accurately represented the installed equipment. Further, WECC has disallowed the use of the model due to its inability to represent voltage-dependent current logic; however, this has not become a practice across North America yet. Not until actual responses of solar PV resources were analyzed by NERC and IRPTF did industry become aware of these shortcomings in the dynamic models. The correct questions are not being asked by the modelers to ensure that the models represent the actual installed equipment.  

**Recommendation:** See A2 recommendation. |
| D3 | **Key Finding:** Attachment A of Appendix 1 in the FERC Large Generator Interconnection Procedures (LGIP) does not mention solar PV resources and only briefly mentions wind power resources. The lack of specificity of information that is used for modeling and studying these resources during the interconnection process may be leading to lack of detailed studies prior to interconnection. Further, it is unclear in the LGIP and the Large Generator Interconnection Agreement (LGIA) what constitutes a material modification and how the technological change procedures should apply when changes (relative to the initial configurations) to the controls, settings, equipment, or other features of a newly interconnecting inverter-based resource will change the electrical response of the resource to disturbance events on the BPS.  

**Recommendation:** The FERC LGIP and LGIA should be reviewed in detail to ensure clarity and consistency for inverter-based resources. The material modification and technological change procedures should be evaluated to ensure that changes to any equipment that change the electrical response of a resources warrant additional interconnection studies to ensure that response is stable under all expected operating conditions.  

**Key Finding:** As the system continues to evolve towards increasing penetrations of inverter-based resources, it is incumbent upon TPs, PCs, and TOs to ensure that interconnection requirements, specifically pertaining to modeling and system studies, are updated to ensure that adequate models (steady-state, dynamic, short circuit, and EMT) are provided and benchmarked. Refer to NERC Reliability Guideline: Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources.  

**Recommendation:** TOs, TPs, and PCs should ensure that the interconnection requirements are updated to ensure adequate models are available for reliability studies during the interconnection studies process. Requirements should be clear and consistent as to what is required to be provided for BPS-connected inverter-based resources. |

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42 The issues associated with representing voltage-dependent current injection are applicable both to MC but also to current injection during ride-through operation.  
43 Benchmarking is particularly important between the dynamic stability models and the EMT models.
<table>
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<tr>
<th>#</th>
<th>Key Findings and Recommendations</th>
</tr>
</thead>
</table>
| D5 | **Key Finding:** As the instantaneous penetration of BPS-connected inverter-based resources (in combination with distributed energy resources) continues to increase, it is becoming increasingly difficult to develop interconnection-wide base cases that meet renewable portfolio standard levels while maintaining acceptable system performance. For example, dispatch conditions of wind and solar PV resources combined with other assumptions in the powerflow base case are leading to intertie flows never previously experienced. These assumptions also impact neighboring footprints and should be established collaboratively with all parties. Entities should develop credible operating assumptions, particularly in the planning horizon with significant amounts of additional variable energy resources dispatched in the case.  

**Recommendation:** Interconnection-wide case creation practices should consider how to manage very high penetration inverter-based resource operating assumptions and also determine any necessary steps or practices to handle previously unexpected operating assumptions that may be leading to system performance issues. |
| D6 | **Key Finding:** The planning model-related challenges being faced are equally a challenge for the stability studies performed during the near-term planning or operations planning time horizons. However, it appears that assumptions are also made in these studies and the modeling improvement efforts in the planning realm by TPs and PCs may not be widely shared with TOPs and RCs. Accurate models are particularly important for studying the “fringe” operating conditions (e.g., high path flows with high renewables conditions) that are relatively unlikely to occur (and may be overlooked in the long-term planning horizon) but may appear in the operations horizon due to outage conditions or other factors. These low-likelihood, high impact operating conditions may pose risks to BPS reliability during certain operating hours.  

**Recommendation:** Transmission planning and operating entities should be coordinating to ensure that any modeling improvements identified in either timeframe are shared and communicated to other entities. Modeling improvements for inverter-based resources should be accounted for in both the planning and operations studies, to the extent possible. Centralized modeling repositories for planning and operations may help ensure accurate models are being applied to both types of studies. |
| D7 | **Key Finding:** The generic RMS positive sequence dynamic models for inverter-based resources connected to the BPS can generally model momentary cessation behavior but with known limitations on modeling the recovery delay. Inaccurate modeling of recovery delay causes inaccuracies in the dynamic simulation results, particularly regarding false voltage overshoot when active current recovery is delayed but reactive current is not. Further, the reec_b model has limitations on capturing voltage-dependent current logic and its use is discouraged moving forward.  

**Recommendation:** The generic RMS positive sequence dynamic models should be enhanced by model development groups\(^{44}\) as soon as possible. Once the model enhancements are benchmarked and approved for use in planning assessments, TPs and PCs should notify GOs in their planning footprint that these updated models are available and should be used for any necessary modeling improvements (regarding MC and other improvements to modeling disturbance ride-through performance). |

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\(^{44}\) Likely the WECC Renewable Energy Modeling Task Force
Appendix B: Model Verification Review

Technically, model verification of individual elements\(^45\) inside an inverter-based resource may be necessary to reach the desired level of detail in these dynamic models. However, this level of verification or testing has proved too complex and costly, and most inverter-based resources dynamic simulations are modeled as an aggregate equivalent. The Applicability section of MOD-026-1 and MOD-027-1 add some confusion to this, stating that “verification for individual units less than 20 MVA ... may be performed using either individual unit or aggregated unit model(s)” but it is unclear which actual versus simulated responses should be compared. The focus should be on ensuring the overall plant response\(^46\) matches between model and actual rather than the response of specific units or aggregated units within an inverter-based resource.

Further, as stated in the body of this report, the comparison of modeled response and actual response to staged tests or recorded disturbance events on the BPS are a requirement of MOD-026-1 and MOD-027-1; however, these comparisons fail to capture the large disturbance behavior of inverter-based resources. Therefore, the dynamic models can be provided to meet compliance with the standards without actually ensuring that that the modeled response actually matches any large disturbance behavior. These gaps in the existing standards should be considered during any development of improved standard requirements.

To illustrate these issues, Table B.1 shows the model parameters for the `regc_a`, `reec_a`, and `repc_a` dynamic models, and describes whether these parameters can be directly verified using commonly applied MOD-026-1 and MOD-027-1 verification tests.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Verified by Test?</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>REGC_A Electrical Generator Model</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

\(^45\) For example, individual turbines in a wind plant or individual inverters in a solar PV facility.

\(^46\) As measured at the Point of Measurement (i.e., high-side of the plant substation transformer(s)).
<table>
<thead>
<tr>
<th>Parameter</th>
<th>Verified by Test?</th>
<th>Comments</th>
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</thead>
<tbody>
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</tr>
<tr>
<td>rrpwr</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td>brkpt</td>
<td>No</td>
<td></td>
</tr>
<tr>
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<td></td>
</tr>
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</tr>
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</tr>
<tr>
<td>accel</td>
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<td></td>
</tr>
<tr>
<td>tg</td>
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<td>Observability of inverter time constant depends on tuning of the active power and volt/var control loops. Inverter time constants are usually small, so tuning of the system must be fast in order to validate this parameter with confidence. It may be difficult to distinguish this parameter from other similar parameters for an aggregate model unless the control system’s internal signals are available.</td>
</tr>
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</tr>
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<td></td>
</tr>
<tr>
<td>xe</td>
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</tbody>
</table>

**REEC_A Electrical Control Model**
### Table B.1: Dynamic Model Parameters Verified by Testing Procedures

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<thead>
<tr>
<th>Parameter</th>
<th>Verified by Test?</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>mvab</td>
<td>Maybe</td>
<td>If this parameter is set erroneously, this may show up in test verification because the per-unitized values of the various quantities would be wrong and this will affect even small disturbance test results.</td>
</tr>
<tr>
<td>vdp</td>
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<td></td>
</tr>
<tr>
<td>vup</td>
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</tr>
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</tr>
<tr>
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</tr>
<tr>
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<tr>
<td>tp</td>
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</tr>
<tr>
<td>qmax</td>
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<td>In cases where this value limits power factor range, it can be quite evident during testing. However, verification of accuracy is unlikely.</td>
</tr>
<tr>
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<td></td>
</tr>
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<td>vmax</td>
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</tr>
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<tr>
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<td>When performing vref step tests at full load, the maximum current limit may be reached.</td>
</tr>
<tr>
<td>tpord</td>
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<td></td>
</tr>
<tr>
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<td></td>
</tr>
<tr>
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<td>The plant response to small disturbances created by capacitor switching tests may reveal incorrect flag settings associated with v/q control mode.</td>
</tr>
<tr>
<td>qflag</td>
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<td>Same reason as above.</td>
</tr>
<tr>
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<td></td>
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<td>pqflag</td>
<td>Yes, maybe</td>
<td>When performing vref step tests at full load, the maximum current limit (Imax) may be reached. P/Q priority may be verified by checking which of the two currents (Iq or Ip) was limited first.</td>
</tr>
<tr>
<td>vq1</td>
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<td></td>
</tr>
<tr>
<td>iq1</td>
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</tr>
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REPC_A Plant-Level Control Model
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<tr>
<td>mvab</td>
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<td>If this parameter is set erroneously, this may show up in test verification because the per unitized values of the various quantities would be wrong, and this will affect even small signal test results.</td>
</tr>
<tr>
<td>tftr</td>
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<td>Observability of inverter time constant depends on tuning of the active power and volt/var control loops. Inverter time constants are usually small, so tuning of the system must be fast in order to validate this parameter with confidence. It may be difficult to distinguish this parameter from other similar parameters for an aggregate model unless the control system's internal signals are available.</td>
</tr>
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<td>kp</td>
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<tr>
<td>ki</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>tf</td>
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<td>tfv</td>
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<td>refflg</td>
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<td>vfrz</td>
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<td>These parameters may be used to replicate ramp behavior during step response tests. Therefore, they may be verified in some cases (but not all).</td>
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Appendix C: Canyon 2 Fire Disturbance NERC Alert Follow-Up

This appendix provides a brief summary of the observations made while reviewing the follow-up information provided to NERC by each entity. These responses identify potential systemic issues with modeling practices for BPS-connected solar PV resources.

**Entity 1 Response**

Entity 1 did not receive any updated dynamic models from solar PV resources in their footprint following the NERC Alert. Entity 1 stated that they rely on MOD-026-1 and MOD-027-1 model submittals for verifying the dynamic models before using those models in the MOD-032-1 case building process. However, as this report highlights, these verification tests likely do not sufficiently verify the large disturbance behavior of inverter-based resources to the degree necessary for TPs and PCs to ensure accurate models are provided. This highlights a potential challenge for this entity regarding BPS-connected inverter-based resource modeling if the entity is solely relying on MOD verification tests to ensure that the dynamic models adequately capture large disturbance behavior.

**Entity 2 Response**

Entity 2 stated that they are using data for one solar PV facility last supplied in 2015. The entity did not receive any updated dynamic modeling information following the NERC Alert. The dynamic models being used include \textit{reec\_b}, and the plant stated that they use MC below 0.6 pu voltage. As explained above, the \textit{reec\_b} model is insufficient to capture MC. The entity did not clarify whether they were proactively addressing this modeling issue with the applicable GO. Therefore, it is unclear if this modeling issue will be addressed.

**Entity 3 Response**

Entity 3 responded that no modeling data from any solar PV resources was received following the NERC Alert. However, this entity has over 800 MW of solar PV resources in its footprint that provided Alert data (responses to actual settings, not modeling data) to NERC following the NERC Alert. All facilities except one use MC during large voltage disturbances. The entity stated that a follow-up enquiry was made with seven facilities that did not produce any additional results. The entity stated that the response provided by the GO for those facilities was that they did not need to take any further action. Upon NERC spot-checking the dynamic models used for these facilities, all facilities use the \textit{reec\_b} dynamic model that is unable to represent MC appropriately. Entity 3 did not provide any additional information regarding future follow-up activities to address these modeling issues. Therefore, there is no indication that these modeling deficiencies have been addressed. Entity 3 should seek immediate model improvements by utilizing MOD-032-1 Requirement R3.

**Entity 4 Response**

Entity 4 received data from 42\%\textsuperscript{47} of its installed solar PV generation fleet (as reported in the 2018 summer base case) and implemented actual data in its simulations for approximately 6900 MW of solar PV plants. For solar PV sites where data was not submitted, generic parameters were used for representing MC based on IRPTF simulation activities. Stability simulations were performed, and the result identified that maximum risk of potential instability occurs when system demand is lowest, solar PV output is highest, and major intertie flows are also high. While these conditions are quite rare, such conditions have occurred in the past. Upon reviewing historical data in 2017 and 2018, it was determined that these conditions occurred 10 hours and 38 hours of the year, respectively. The simulations showed that the system remains stable for fault events and subsequent MC of a wide area of solar PV generating resources. Under light load conditions, a significant frequency event occurs (although does not reach UFLS activation levels); under high transfer conditions, a significant transient voltage swing occurs along the major interties. In addition, it is unclear whether Entity 4 will be following up with the other 58\% of the solar PV fleet to incorporate actual data in future simulations.

\textsuperscript{47} This represents many thousands of MW of solar PV.
**Entity 5 Response**

Entity 5 stated that they did not receive any updated models following the NERC Alert for existing solar PV facilities nor any models of proposed changes to equipment. For this reason, Entity 5 stated that no reliability studies were performed due to the lack of model submittals. Entity 5 also stated that the existing models do not adequately represent MC behavior. They expressed that risk exposure is likely limited due to the fact that BES solar PV resource penetration is relatively low and is less than the generation loss for their largest single contingency. Entity 5 stated that upon receipt of any updated models, reliability simulations would be performed to study any potential instability conditions. They offered to continue providing support to GOs regarding updating and supplying their dynamic models; however, there was no concrete timeline or description of a proactive effort to get these modeling issues addressed. As the penetration of solar PV continues to grow in this region, Entity 5 will need to be more proactive in addressing known modeling issues.

**Entity 6 Response**

Entity 6 stated that they had one applicable facility regarding the NERC Alert, and that no modeling changes were needed because the dynamic model represents the expected behavior of the facility. However, NERC reviewed the dynamic model for this resource in the latest interconnection-wide base case and compared the model with the submitted NERC Alert data and identified that they are not consistent. The resource utilizes MC for large disturbance behavior; however, the GO submitted the reec.b model that does not have the capability to accurately represent MC. Therefore, it is concerning that the entity provided such response that stated no further action is needed. This identifies a potential lack of understanding of the dynamic models for BPS-connected inverter-based resources for this entity. The entity stated that no proposed changes were needed and that no follow-up activities are planned. Further analysis by NERC identified that this specific inverter manufacturer is able to eliminate MC for its fleet of inverters. Again, this identifies a lack of effort by the entity to drive improvements in performance of their applicable solar PV facilities.

**Entity 7 Response**

Entity 7 failed to respond to the NERC request for follow-up activities; additional outreach by NERC led to informal responses from the entity. Three solar PV facilities (couple hundred MW) in their footprint use MC that was not originally captured by the dynamic models. The GO provided updated dynamic models for these facilities that were determined to accurately capture MC. Entity 7 also requested the GO to update their inverters to eliminate MC and provide updated models. As a result, the models representing MC were not incorporated into the area-wide base case and the models using the other forms of ride-through were used instead. The entity notified their PC and RC when the GO completed upgrades to eliminate MC. Subsequently, the entity has now modified their interconnection requirements to prohibit MC within the PRC-024 No Trip zone for all new plants.

**Entity 8 Response**

Entity 8 stated that they identified discrepancies between the submitted data and the dynamic models provided as part of the NERC Alert. Specifically, most issues were associated with the GOs using default model parameters or parameters that did not reflect the expected performance (as confirmed with the GO). These issues were resolved through an iterative process of data exchange between the entity and the GO (and often with their OEMs). Reliability studies performed by the entity used a high inverter-based resource output under light load conditions. Two solar PV facilities with updated dynamic modeling data exhibited questionable behavior after fault clearing and contributed to both overvoltage conditions and subsequent resource tripping. Although this response did not exhibit MC and did not trigger instability, cascading, or uncontrolled separation, it was considered unacceptable dynamic behavior. The entity communicated these findings to the respective GOs, and the GOs are in the process of reviewing the model data provided.

**Entity 9 Response**

Entity 9 stated that they only have one applicable BES solar PV facility in their footprint, and that facility does not use MC so no changes were made. The entity stated that they reviewed the data submitted by the GO to resolve issues pertaining to the large disturbance logic and settings in the dynamic model (e.g., $V_{dip}$, $V_{up}$, $V_{frz}$, $I_{qmax}$, $I_{qmin}$) to avoid
erroneous behavior for large disturbances. This was a very positive response, with the TP being proactive in ensuring appropriate dynamic modeling and parameterization of the models beyond a simple cursory review of the submittals.

**Entity 10 Response**

Entity 10 stated that they received NERC Alert data (spreadsheet) from 65 solar PV facilities. While the NERC Alert data was only required for BES resources, they did receive information for some non-BES resources (but not many). The total capacity of the 65 facilities is over 7000 MW. Most of the inverters currently use MC as a means of voltage ride-through, and more than half can eliminate the use of MC according to the NERC Alert data provided.

Although the NERC Alert recommended that updated dynamic models be provided by the GOs, only 13 submissions of dynamic models were received by Entity 10. Deficiencies were identified in every submitted model (i.e., no submitted models were deemed acceptable). Most commonly, the GO provided a dynamic model in the wrong format or with parameter values that did not match the NERC Alert data submitted. No dynamic models were received for proposed changes in settings.

Due to the lack of information and updated models provided during the NERC Alert process, Entity 10 has initiated a comprehensive modeling improvement effort over the course of multiple years to receive accurate and updated dynamic model information for all its market participants. Entity 10 will notify the GOs of model improvement requirements that must be met by the GOs within a set timeframe. Entity 10 is also working with the GOs to ensure approval of changes to inverter settings to improve solar PV performance during large disturbance events. After the changes are implemented in the field, GOs are required to submit the updated dynamic models to Entity 10 and their applicable TPs. Entity 10 will follow up with the GOs following the model submission and review process to track, retain, and use the updated models.

Entity 10 proactively updated the dynamic modeling errors described above using the NERC Alert data received. These updates were made to each facility, and stability simulations were performed to ensure reliability criteria was met using the updated models. Model updates were only made to solar PV facilities in the Entity 10 footprint; no models were changed outside their footprint since data was not available (i.e., not shared amongst PCs). Stability studies on light load and peak load cases were performed. No reliability concerns caused by existing MC settings were identified. A few parameter values associated with a large solar PV facility in one area of their planning area could have an impact on load bus voltages in a neighboring TP area in their footprint. While acceptable performance was met, this strengthened the importance of model accuracy for the entity. Studies of proposed changes identified improvements to BPS performance following fault events (i.e., less MC, faster power output recovery, less impacts to system frequency).

Since so many model deficiencies were identified and incomplete modeling data was supplied by GOs, the studies do not adequately assess the individual facilities’ dynamic characteristics. Therefore, the studies do not provide the information needed to support approval of the proposed settings. However, NERC recognizes that minimizing the impacts of MC is an imminent concern. Given that the proposed setting changes align with the NERC recommendation to improve the reliability, Entity 10 recommended to GOs to make the proposed changes to equipment settings. Entity 10 has also improved its procedures for collecting modeling data from generating resources by improving its modeling requirements to provide clarity and consistency to the model submittals.

The entity stressed the criticality of accurate models for ensuring BPS reliability. This includes models of existing installed equipment in the facilities, and ensuring that any changes to such equipment are accurately reflected in updated dynamic models. The entity also stressed that the vast number of modeling deficiencies identified highlights a systemic modeling challenge for the industry moving forward. While Entity 10 is proactively trying to address these known modeling issues, they recommend industry-wide efforts to correct these modeling errors as quickly as possible.
**Entity 11 Response**

Entity 11 stated that they have utilized MOD-032-1 Requirement R3 to gather representative modeling information after identifying issues with the submitted data for solar PV facilities. The most common issue with the submitted models was using models that are no longer approved by the MOD-032 Designee (and hence the TP). Specifically, the `reec_b` model was submitted multiple times for different solar PV facilities. This required back-and-forth feedback between the entity and the GOs to convert these models to acceptable models. Most of the updated dynamic model data was deemed acceptable by the entity; several submittals are still pending confirmation by the entity. One solar PV facility failed initialization testing, and is being re-evaluated. A couple of the solar PV resources were previously represented using the Type 4 wind plant models (first generation models) with no associated protection models. These are being updated to the latest generation of renewable energy system models.

**Entity 12 Response**

Entity 12 received initial data from one BES solar PV facility, which utilizes MC. Over the course of two months, the entity had several communications with the solar PV facility to clarify information and address data formats and model parameter issues from the initial submittal. The entity stated that they are stressing that solar PV resources should be designed to eliminate or minimize MC. However, there was no mention of improving interconnection requirements to reflect this recommended performance specification. The entity also stated that no proposed model was provided to eliminate MC, and hence no further studies have been performed. They stated that since no model was provided, no follow-up activities have occurred and did not describe any plans to do so.

**Entity 13 Response**

Entity 13 stated that no updated data was provided from the applicable GOs following the NERC Alert; however, the entity stated that they did not identify any issues with the existing data (i.e., the models previously supplied by the GOs are accurate and sufficient). However, NERC reviewed at least one of the applicable units and identified that the inverters use MC for voltage less than 0.45 pu (based on NERC Alert data provided) but submitted the `reec_b` model that cannot accurately capture MC. Further, it was noted that the data supplied during the NERC Alert for this solar PV facility stated that the plant uses a 10%/second ramp rate recovery, which requires 10 seconds to recover to pre-disturbance current injection following MC. Such performance does not meet the recommended performance as specified by IRPTF. Further, reviewing the NERC Alert data, NERC identified that the proposed settings provided by the GO actually result in degraded performance from the inverters for large disturbance events. Entity 13 stated that they did not receive any proposed model and therefore did not perform any studies related to these proposed settings. Therefore, it is unclear the extent of this modeling gap and this example also illustrates a lack of review and potential system modeling issue for this entity.

**Entity 14 Response**

Entity 14 stated that it commonly identified that solar PV and wind facilities do not pass dynamics data checks, including:

- Models often have initialization errors that preclude their use in dynamic simulations.
- Models often do not have a flat dynamic response for no disturbance simulations up to 30 seconds.
- Models often do not exhibit positive damping for normally cleared fault events.
- Models often do not have proper vetting against data provided by the inverter manufacturer (i.e., the data provided does not match the dynamic model parameters).
- Models are often netted or disabled in the interconnection-wide base case due to system modeling errors that cannot be easily addressed by the MOD-032 Designee during base case creation processes.

This entity has over 600 MW of solar PV facilities in its footprint. The entity did not receive an updated dynamic model from any of its solar PV GOs following the NERC Alert, for either existing equipment or proposed changes.
NERC reviewed the information submitted by the GOs in the area of Entity 14. The largest solar PV facility in this area, consisting of multiple phases of different inverter types, stated that the facility utilizes MC below around a 0.9 pu voltage threshold for different inverter types. The data provided also stated that MC can be eliminated for all types of inverters at this facility. Further, the existing models include reec_b, which cannot represent MC suitably. Entity 14 did not state that any follow-up activities were planned to correct these issues.

The lack of updated dynamic models and no models provided for proposed settings, in combination with the lack of activities to proactively or reactively address these modeling issues, is identified as a systemic modeling and procedural issue for Entity 14.

**Entity 15 Response**

Entity 15 stated that upon receipt of the NERC Alert, they held conference calls with each of the GOs with solar PV facilities to discuss the answers provided. However, no dynamic models were provided by the GOs regarding existing equipment or proposed changes. The entity stated that their planning engineers updated some of the dynamic model voltage trip settings based on the NERC Alert data provided; however, these updated models did not come from the GOs directly.

The entity stated that no models of proposed changes in equipment were provided by the GOs, and therefore, no follow-up studies or activities were planned by the entity. This shows a lack of proactive action to address potential modeling issues by this entity. NERC reviewed the NERC Alert data for applicable solar PV facilities and noted that multiple facilities currently use MC with a low voltage threshold around 0.9 pu, and that those facilities stated they could eliminate MC. However, with the lack of follow-up by this entity, it is unclear if the changes were made and if the dynamic models actually reflect behavior of the installed resources.
Contributors

NERC gratefully acknowledges the contributions and assistance of the following individuals in the preparation of this report and support to the studies performed by the NERC IRPTF. NERC also would like to acknowledge the technical discussions and contributions of the NERC IRPTF.

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<tr>
<td>Hassan Baklou</td>
<td>San Diego Gas and Electric</td>
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<tr>
<td>Jeff Billo (IRPTF Vice Chair)</td>
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<td>Brad Marszalkowski</td>
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Reception Agenda
March 3, 2020 | 5:30-7:00 p.m. Eastern

Atlanta Marriott Marquis Hotel
265 Peachtree Center Avenue
Atlanta, GA 30303

Conference Room: Marquis Ballroom Salon D

Please join us at the Reception to take an opportunity to reflect on the work of the Operating, Planning, and Critical Infrastructure Committees and to say goodbye and thank you to a long-time colleague and friend, Bob Cummings.

Agenda

- Welcome Remarks by Mark Lauby, Senior Vice President and Chief Engineer
- Remarks by Jim Robb, NERC President and CEO
- Remarks by Ken DeFontes, Chair-Elect/Vice Chair, NERC Board of Trustees
- Remarks by Greg Ford, Chair, RSTC
- Remarks by Operating, Planning, and Critical Infrastructure Protection Committees’ Chairs
- Remarks by Bob Cummings, Senior Director of Engineering and Reliability Initiatives