Agenda
Reliability and Security Technical Committee

October 14, 2020 | 1:00–4:00 p.m. Eastern Time

Attendee Webex Link

Call to Order

NERC Antitrust Compliance Guidelines and Public Announcement

Introductions and Chair's Remarks

Administrative items

1. **Announcement of Quorum**
2. **Meeting Governance**

Regular Agenda

2. **Remarks - Greg Ford, RSTC Chair**
3. **Concept Paper: Integrating Security Topics into RSTC Technical Groups* – Accept - Ryan Quint, NERC Staff**
   This concept paper is intended to support efforts of the RSTC to incorporate cyber and physical security considerations within the scope of every RSTC technical group. Seeking RSTC to accept the concepts paper for each subgroup to consider ways to integrate security into their scope.
4. **SAR for Revisions to MOD-025-2 - Unit Verification and Modeling*– Endorse** – Shawn Patterson, PPMVTF Chair
   The PPMVTF has prepared a draft SAR that aligns with the previously approved white paper findings and is seeking RSTC endorsement to submit the SAR to the Standards Committee.
5. **SAR for Revisions to PRC-023-4 – Transmission Relay Loadability*– Endorse** – Jeff Iler, Chair SPCWG
   The SPCS developed a PRC-023-4 SAR and requested NERC Planning Committee review in December 2018. The SAR was revised based on the comments received and is seeking endorsement to submit the SAR to the Standards Committee.
6. **Reliability Guideline: Gas and Electrical Operational Coordination Considerations*** – **Accept to Post Document for 45-day Comment Period** – Chris Pilong, ORS Chair
   The Reliability Guideline: Gas and Electrical Operational Coordination Considerations was revised by the Operating reliability Subcommittee and endorsed at its September 2020 meeting. The Operating Reliability Subcommittee and Electric-Gas Working Group will coordinate a comment

period, review and update for the Reliability Guideline. These two groups are seeking acceptance to post the document for a 45-day public comment period.

7. **Reliability Guideline: Model Verification of Aggregate DER Models Used in Planning Studies* – Accept to Post Document for 45-day Comment Period** – Kun Zhu, SPIDERWG Chair

   This guideline provides TPs and PCs with tools and techniques can be adapted for their specific systems to verify that the aggregate DER models created are a suitable representation of these resources in planning assessments. SPIDERWG asks the RSTC to accept posting this Reliability Guideline: Model Verification of Aggregate DER Models used in Planning Studies for a 45 day industry commenting period as per the approval process for Reliability Guidelines.

8. **White Paper on Assessment of DER Impacts on NERC Reliability Standard TPL-001* – Approve** – Kun Zhu, SPIDERWG Chair

   The intent of the white paper is to highlight potential gaps or areas for improvement within TPL-001 along with some potential solutions such that a SAR or an implementation guide can be developed, as needed, to address various issues by a SDT. SPIDERWG asks the RSTC to approve the white paper.

9. **SITES Scope and Work Plan – Update**
   We want to update you on SITES Scope document review and ask for volunteers to assist in the revision of the Scope Document

10. **Chair's Closing Remarks and Adjournment**

*Background materials included.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Antitrust Compliance Guidelines

I. General

It is NERC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. This policy requires the avoidance of any conduct that violates, or that might appear to violate, the antitrust laws. Among other things, the antitrust laws forbid any agreement between or among competitors regarding prices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that unreasonably restrains competition.

It is the responsibility of every NERC participant and employee who may in any way affect NERC's compliance with the antitrust laws to carry out this commitment.

Antitrust laws are complex and subject to court interpretation that can vary over time and from one court to another. The purpose of these guidelines is to alert NERC participants and employees to potential antitrust problems and to set forth policies to be followed with respect to activities that may involve antitrust considerations. In some instances, the NERC policy contained in these guidelines is stricter than the applicable antitrust laws. Any NERC participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NERC's antitrust compliance policy is implicated in any situation should consult NERC's General Counsel immediately.

II. Prohibited Activities

Participants in NERC activities (including those of its committees and subgroups) should refrain from the following when acting in their capacity as participants in NERC activities (e.g., at NERC meetings, conference calls and in informal discussions):

- Discussions involving pricing information, especially margin (profit) and internal cost information and participants' expectations as to their future prices or internal costs.
- Discussions of a participant's marketing strategies.
- Discussions regarding how customers and geographical areas are to be divided among competitors.
- Discussions concerning the exclusion of competitors from markets.
- Discussions concerning boycotting or group refusals to deal with competitors, vendors or suppliers.

- Any other matters that do not clearly fall within these guidelines should be reviewed with NERC's General Counsel before being discussed.

III. Activities That Are Permitted

From time to time decisions or actions of NERC (including those of its committees and subgroups) may have a negative impact on particular entities and thus in that sense adversely impact competition. Decisions and actions by NERC (including its committees and subgroups) should only be undertaken for the purpose of promoting and maintaining the reliability and adequacy of the bulk power system. If you do not have a legitimate purpose consistent with this objective for discussing a matter, please refrain from discussing the matter during NERC meetings and in other NERC-related communications.

You should also ensure that NERC procedures, including those set forth in NERC's Certificate of Incorporation, Bylaws, and Rules of Procedure are followed in conducting NERC business.

In addition, all discussions in NERC meetings and other NERC-related communications should be within the scope of the mandate for or assignment to the particular NERC committee or subgroup, as well as within the scope of the published agenda for the meeting.

No decisions should be made nor any actions taken in NERC activities for the purpose of giving an industry participant or group of participants a competitive advantage over other participants. In particular, decisions with respect to setting, revising, or assessing compliance with NERC reliability standards should not be influenced by anti-competitive motivations.

Subject to the foregoing restrictions, participants in NERC activities may discuss:

- Reliability matters relating to the bulk power system, including operation and planning matters such as establishing or revising reliability standards, special operating procedures, operating transfer capabilities, and plans for new facilities.
- Matters relating to the impact of reliability standards for the bulk power system on electricity markets, and the impact of electricity market operations on the reliability of the bulk power system.
- Proposed filings or other communications with state or federal regulatory authorities or other governmental entities.
- Matters relating to the internal governance, management and operation of NERC, such as nominations for vacant committee positions, budgeting and assessments, and employment matters; and procedural matters such as planning and scheduling meetings.

In all cases, a final report may be considered for approval, endorsement, or acceptance if the RSTC, as outlined above, decides to act sooner.

Possible Actions for other Deliverables

1. **Approve:**

   The RSTC has reviewed the deliverable and supports the content and development process, including any recommendations.

2. **Accept:**

   The RSTC has reviewed the deliverable and supports the development process used to complete the deliverable.

3. **Remand:**

   The RSTC remands the deliverable to the originating subcommittee, refer it to another group, or direct other action by the RSTC or one of its subcommittees or groups.

4. **Endorse:**

   The RSTC agrees with the content of the document or action, and recommends the deliverable for the approving authority to act on. This includes deliverables that are provided to the RSTC by other NERC committees. RSTC endorsements will be made with recognition that the deliverable is subject to further modifications by NERC Executive Management and/or the NERC Board. Changes made to the deliverable subsequent to RSTC endorsement will be presented to the RSTC in a timely manner. If the RSTC does not agree with the deliverable or its recommendations, it may decline endorsement. It is recognized that this does not prevent an approval authority from further action.

Concept Paper: Integrating Security Topics into RSTC Technical Groups

Action

Accept the concepts paper for each subgroup to consider ways to integrate security into their scope.

Summary

Security, both cyber and physical, plays a vital role in ensuring the reliability of the bulk power system. It is envisioned that each RSTC subgroup will consider security in its work plan and work products as a normal course of action. The RSTC Transition Team (RSTCTT) developed the *Integrating Security Topics into RSTC Technical Groups* document as an introductory means to use as a framework by sponsors, NERC staff, and subgroup leadership to integrate security into their respective work plans and products. This document is intended to support efforts of the RSTC to incorporate cyber and physical security considerations within the scope of every RSTC subgroup.

Concept Paper: Integrating Security Topics into RSTC Technical Groups

NERC BPS Security and Grid Transformation Group
August 2020

Purpose

This paper is intended to support efforts of the NERC Reliability and Security Technical Committee (RSTC) to incorporate cyber and physical security considerations within the scope of every RSTC technical group. For purposes of this discussion, "security" will be used as a comprehensive term that can refer to cyber and/or physical security of a system, process, environment, or device.

These suggestions are intended to fuel discussions that support a holistic approach to security, in the context of Bulk Power System (BPS) reliability activities that the RSTC supports. It is intended that each group, under the direction of the RSTC, uses this information as a starting point for considering how their work plans can reflect high priority security-related topics.[1]

Review of NERC Technical Groups and Considerations for Security Topics

The following suggestions are examples of the physical and cyber security topics that may be appropriate for RSTC subcommittees, working groups, or task forces to consider or address:

- **Performance Monitoring:**
  - **Real-Time Operations Subcommittee (RTOS):** The RTOS, being focused primarily on real-time operations, should consider how cyber threats may pose potential risks to BPS reliability and ensure that operating plans and operating procedures clearly specify how security incidents will be handled. This should include guidance and recommended practices for system restoration and blackstart under possible cyber threat scenarios.
  - **Performance Analysis Subcommittee (PAS):** The PAS may consider ways to track cybersecurity incidents in a manner that provides useful information for the annual NERC State of Reliability report.
  - **Event Analysis Subcommittee (EAS):** The EAS may look at security threats and consider what constitutes a "reportable incident," in coordination with NERC E-ISAC activities. An outcome of this effort could be a lessons learned document or other work product that could bring value to the entire industry.

[1] These activies can further support other industry references and guidance materials that can help organizations better understand and improve their management of security risks. The National Institute of Standards and Technology (NIST) Cybersecurity Risk Framework (CSF) is a widely used resource that specifically addresses critical infrastructure. Other resources include those from the Department of Homeland Security (DHS) or organizations such as ASIS International or (ISC)².

  - **Resources Subcommittee (RS):** The RS could provide guidance about the impact that security incidents could have on balancing issues and how those threats relate to balancing reserves, system frequency, and other relevant factors.

- **Risk Mitigation:**
  - **Inverter-Based Resource Performance Working Group (IRPWG):** The IRPWG should use its expertise to provide clear guidance and recommended practices for ensuring security threats are minimized at inverter-based facilities. This includes potential physical and cybersecurity threats that may affect individual inverters or plant-level controllers or threats that could have a more wide-ranging impact.
  - **Electromagnetic Pulse Task Force (EMPTF):** EMPTF is continuing its efforts related to EMP threats to the BPS. The EMPTF will be providing guidance on potential EMP threats and how to mitigate them; no further action needed.
  - **System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG):** The SPIDERWG should consider how security threats, predominantly cybersecurity, may pose risks to the BPS due to the widespread nature of distributed energy resources. In particular, the introduction of distributed energy resource management systems (DERMS) should be addressed, particularly how DERMS may introduce cybersecurity threats to the overall BPS and how industry could address those risks.
  - **Geomagnetic Disturbance Task Force (GMDTF):** The GMDTF is addressing impacts of geomagnetic disturbances as a possible BPS reliability risk. Physical and cyber security aspects are outside the scope of GMDTF activities.
  - **Power Plant Modeling and Verification Task Force (PPMVTF):** The PPMVTF could provide guidance regarding physical and cybersecurity threats to different types of power plants across North America and ways to mitigate BPS risks imposed by those threats.
  - **Security Working Group (SWG):** With its legacy of focusing on both cyber and physical security issues that threaten BPS reliability, the SWG is positioned to continue addressing those topics. In addition, it should be recognized as a resource pool for other RSTC groups as they seek feedback or participation related to their relevant security matters.
  - **Load Modeling Working Group (LMWG):** The LMWG recommends practices and guidance to industry related to load modeling in reliability studies, so physical and cyber security topics are likely to be outside their scope.
  - **Electric-Gas Working Group (EGWG):** The EGWG has focused on how threats or contingencies to the gas network may impact BPS operations on the electric side, primarily from a physical security perspective. This effort could be expanded to perform similar evaluations of cyber threats that could impact BPS operations through the electric-gas interface. Identifying these types of threats could help BPS planners and operators be aware of potential widespread impacts and help industry develop mitigating actions.

- **Supply Chain Working Group (SCWG):** The SCWG is providing clear guidance regarding supply chain risks that can pose cybersecurity threats to the BPS. No further action is needed by SCWG to consider security aspects.
- **System Protection and Control Working Group (SPCWG):** The SPCWG could provide significant guidance to industry regarding ways in which BPS protection systems may be impacted by physical and cyber security threats. Specifically, the SPCWG could provide guidance on the types of security threats to which protective relaying and control systems are vulnerable and possible approaches to mitigating those threats.
- **Security and Reliability Training Working Group (SRTWG):** The merger of security, planning, and operating functions within the RSTC is well suited for a combined effort. Training and outreach can address all three formerly distinct topics with a focus on areas of common concern.

- **Reliability and Security Assessment:**
  - **Reliability Assessment Subcommittee (RAS):** The RAS may consider including key takeaways and findings from the various groups in the NERC Long Term Reliability Assessment each year. This may include coordinating with other groups to determine possible future BPS reliability risks caused by security threats.
  - **Emerging Technologies and Grid Transformation Subcommittee (ETGTS):** The ETGTS will focus specifically on new technologies and the changing grid, and provide guidance and strategic vision to how industry can adapt to these changes in a reliable and resilient manner. The ETGTS may coordinate with other groups to determine and prioritize possible security risks, as well as provide industry with guidance and strategy needed to adopt new technologies in a secure manner.

These suggestions are examples of how RSTC groups can ensure that work plans sufficiently and completely address the security concerns implicit in BPS planning, operations, design, and restoration. Security has become an increasingly critical aspect of BPS reliability, so addressing physical and cyber security in the context of each facet is more important than ever before.

Power Plant Modeling and Verification Task Force
SAR for the Revision of MOD-025-2

Action
Endorse to submit the SAR to the Standards Committee.

Background
The PPMVTF prepared a white paper documenting issues with MOD-025-2, concluding that the stated purpose of ensuring 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, is not being met by the standard. The PPMVTF recommends in the white paper that a SAR be drafted for the modification of MOD-025-2 and a standard drafting team be created to correct these issues.

The RSTC approved the white paper and authorized PPMVTF to draft a SAR for the revision of MOD-025-2 at their June 10, 2020 meeting. The task force has subsequently prepared a draft SAR that aligns with the white paper findings and is seeking RSTC endorsement to submit the SAR to the Standards Committee.

Summary
The PPMVTF has prepared a draft SAR that aligns with the previously approved white paper findings and is seeking RSTC endorsement to submit the SAR to the Standards Committee.

Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the NERC Help Desk. Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	MOD-025-2 Verification and Data Reporting of Generator Capability		
Date Submitted:	MM/DD/YYYY		
SAR Requester			
Name:	Shawn Patterson, Chair		
Organization:	NERC Power Plant Modeling Verification Task Force (PPMVTF)		
Telephone:	303-445-2311	Email:	spatterson@usbr.gov

SAR Type (Check as many as apply)	
☐ New Standard ☒ 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)	
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan	☒ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☐ Industry Stakeholder Identified

Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):
The current industry need for this standards project is that industry implementation of MOD-025-2 has not resulted in useful unit capability data being provided for planning models of generating resources and synchronous condensers (i.e., the purpose statement of the standard). The primary reliability benefit of this project will be to correct these issues such that suitable and accurate data can be established through the verification activities performed by respective equipment owners. BPS planning assessments rely on accurate data, including machine active and reactive power capability, to identify potential reliability risks and develop mitigating actions for those risks. The current MOD-025-2 verification testing activities require significant time, expertise, and coordination; however, they do not result in data that should be used by planners for modeling purposes. The current standard does allow for optional calculations to be performed to help facilitate better information sharing; however, calculations are not required nor can be used in many cases when auxiliary equipment limits or system operating conditions prohibit reaching the actual machine capability or limiters. This standards project will address these issues.

Requested information
Other benefits of this standards project to address issues with MOD-025-2 include, but are not limited to, the following: • Preventing over- or under-estimation of generating facility active and reactive power, which could lead to potential reliability risks or unnecessary and expensive solutions to mitigate • Identifying limitations within a generating facility that could constrain the resource from reaching the expected active/reactive capability at any given time • More clearly communicating the necessary data to be used for modeling the respective resources in steady-state power flow models • Ensure that the data users are part of the verification process to ensure that the necessary and usable data is provided and utilized appropriately • Ensure that raw test data alone is not used for resource modeling, but is analyzed, adjusted, and contextualized to account for measured system conditions • Coordinating with PRC-019 activities to develop a composite capability curve, inclusive of equipment capabilities, limiters, and other plant limitations to develop an appropriate capability curve • Ensuring that other means of verification (other than testing) can be more effectively leveraged to gather necessary and suitable data for verifying plant/machine capability
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
The intent of this standard revision project is to address the issues that exist with MOD-025-2 regarding verification and data reporting of generator active and reactive power capability (and any other relevant equipment capability). Currently, implementation of the standard rarely produces data that is suitable for planning models (i.e., the stated purpose of the standard). The vast majority of testing cases are limited by limits within the plant or system operating conditions that prohibit the generating resource from reaching its “composite capability curve” – the equipment capability or associated limiters. The goal of the proposed project is to: • Ensure that testing and other verification activities produce useful data for verification of plant active and reactive power capability • Ensure that the data is used by Transmission Planners and Planning Coordinators in an appropriate manner, with a sufficient degree of analysis prior to use • Ensure that the data is applicable and usable by the Transmission Planner and Planning Coordinator for reliability studies • Ensure Generator Owners appropriately identify limits within their generating resources (and synchronous condensers), and effectively communicate those limits to Transmission Planners and Planning Coordinators for the purposes of modeling these resources in reliability studies
Project Scope (Define the parameters of the proposed project):
The scope of this project is to modify MOD-025-2 to ensure that data provided through verification activities performed by applicable Generator Owner or Transmission Owners produce suitable data for

Requested information
the purposes of developing accurate planning models in Transmission Planner and Planning Coordinator reliability studies. The project should consider, at a minimum, the following: 1. Revisions to MOD-025-2 to ensure that verification activities produce data and information that can be used by Transmission Planners and Planning Coordinators for the purposes of developing accurate and reasonable plant active and reactive capability data (including possibly representation of the "composite capability curve" inclusive of capability and limiters, where applicable). 2. Ensure that each Planning Coordinator and the area Transmission Planners develop requirements for the Planning Coordinator area real and reactive capability data verification 3. Ensure that Generator Owners provide the data specified by the Planning Coordinator and Transmission Planners for the Planning Coordinator area 4. Ensure that verification activities can apply other methods beyond only testing (or real-time data) that allow plant capability information, protection settings, PRC-019 reports, and other documentation to also complement the verification activities 5. Ensure that data provided by the applicable Generator Owners and Transmission Owners is analyzed and used appropriately by Transmission Planners and Planning Coordinators 6. Ensure that the data provided by Generator Owners, if different from tested values, is acceptable to the Planning Coordinator and Transmission Planners with the standard providing guidance on acceptable reactive capability reporting if system conditions prevent reaching actual capability. 7. Ensure alignment of the MOD-025 standard with MOD-032-1 regarding data submittals for annual case creation and PRC-019-2 regarding collection of information that can be effectively used for verification purposes. Ensure activities across standards can be applied to effectively meet the purpose of these standards, and avoid any potential overlap or duplication of activities. This is dependent on the success of bullet number 1. 8. Ensure that equipment limitations are documented and classified as expected (e.g., system voltage limit reached) or unexpected (e.g., plant tripped or excitation limiter reached unexpectedly). In cases of unexpected limitations reached, ensure that the equipment owner develops and implements a corrective action plan to address this unexpected limitation.
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[1] 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):
The NERC PPMVTF developed *White Paper: Implementation of NERC Standard MOD-025-2*[2] that recommends NERC initiate a standards project to address these issues with MOD-025-2. The white paper provides a detailed description and technical justification of the gaps that exist in MOD-025-2 and

[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] https://www.nerc.com/comm/PC/Power%20Plant%20Modeling%20and%20Verification%20Task%20Force/PPMVTF_White_Paper_MOD-025_Testing.pdf

Requested information
how the current standard may be leading to inaccurate data being used in BPS reliability studies. Further, the NERC PPMVTF *Reliability Guideline: Power Plant Model Verification and Testing for Synchronous Machines*[3] also describes in detail how testing activities per MOD-025-2 can lead to unusable data, and provides further guidance that a SDT could use to develop solutions to these issues.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The aforementioned NERC PPMVTF *White Paper: Implementation of NERC Standard MOD-025-2* includes an example of one Registered Entity's MOD-025 implementation costs (excluding cost of shifting the optimization of generation fleet assets due to minimum load testing requirements). The entity's average test cost was $1,259 (897 tests) and $4,326 per generator (261 generators). The verification testing of units generally results in transferring energy to a higher cost resource during the test period. Further, the data produced is often NOT suitable for planning studies, which does not serve the intended purpose of the standard and makes the added cost unjustified.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
The current MOD-025-2 was written around synchronous generation, although it is not specifically applicable only to synchronous generators. Therefore, the project should ensure the language is clear and concise regarding how to handle BES dispersed generating resources (e.g., wind, solar photovoltaic, and battery energy storage systems).
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):
• Generator Owner and Transmission Owner of synchronous condensers (asset owner that is in the best position to ascertain resource capability) • Transmission Planner and Planning Coordinator (user of the information provided by the Generator Owner; currently has no responsibility of ensuring accurate data per current MOD-025-2 standard)
Do you know of any consensus building activities[4] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
The NERC PPMVTF White Paper, approved by NERC RSTC, details the challenges with MOD-025-2. The team deliberated this subject for a significant amount of time, and have identified major issues with the standard that need to be addressed by an SDT. The PPMVTF believes that a significant revision to MOD-025-2 is needed, that testing activities are useful and should be retained, but that the activities can

[3] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_PPMV_for_Synchronous_Machines_-_2018-06-29.pdf
[4] 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.

Requested information
focus on more effective means of collecting useful data for planning models. One dissenting opinion of PPMVTF membership believed the standard should be retired completely and not replaced with an alternative.
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)?
The NERC standards development Project 2020-02 (Transmission-connected Dynamic Reactive Resources) SAR includes MOD-025-2, specifically addressing the applicability of transmission connected reactive devices in addition to generators and synchronous condensers. The SAR on PRC-019-2 submitted to NERC by the System Protection and Control Subcommittee is also related in that there is significant overlap of activities in PRC-019-2 and the development of planning models of machine capability. This SAR could be combined with those portions of those SARs to address this problem effectively.
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.
There are two key industry reference documents on this subject: 1. NERC *Reliability Guideline: Power Plant Model Verification and Testing for Synchronous Machines*[5] (July 2018) that provides recommended practices for synchronous machine capability testing. An appendix is devoted to MOD-025-2 testing, and highlights the challenges and inherent errors in MOD-025-2 to obtain useful data that can be applied for planning models. 2. NATF *Modeling Reference Document Reporting and Verification of Generating Unit Reactive Power Capability for Synchronous Machines*[6] (April 2015) that describes testing activities per MOD-025-2 and means of ensuring data is sufficient for planning studies. Neither industry reference document addresses the identified shortcomings of the standard described above and in NERC PPMVTF *White Paper: Implementation of NERC Standard MOD-025-2*.[7] These reference materials help industry understand how to implement the standards using best practices, but do not address the reliability gaps created by the standard requirements themselves which is leading to inaccurate data being used in planning assessments.

[5] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_PPMV_for_Synchronous_Machines_-_2018-06-29.pdf
[6] https://www.natf.net/docs/natf/documents/resources/planning-and-modeling/natf-reference-document-reporting-and-verification-of-generating-unit-reactive-power-capability-for-synchronous-machines.pdf
[7] https://www.nerc.com/comm/PC/Power%20Plant%20Modeling%20and%20Verification%20Task%20Force/PPMVTF_White_Paper_MOD-025_Testing.pdf

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.
☐	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	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
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.	Yes

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
N/A	None identified.

For Use by NERC Only

SAR Status Tracking (Check off as appropriate).	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template
3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk
4	February 25, 2020	Standards Information Staff	Updated template footer

SAR for Revisions to PRC-023-4 – Transmission Relay Loadability

Action
Endorse to submit the SAR to the Standards Committee.

Background
The SPCS developed a PRC-023-4 SAR and requested NERC Planning Committee review in December 2018. The SAR was revised based on the comments.

Requirement R2, in PRC-023-4, requires applicable functional entities to set their Out of Step Blocking (OOSB) elements to allow tripping for faults during the loading conditions prescribed by Requirement R1. A requirement to allow tripping in a Standard whose intent is to block tripping, has led to some entities disabling their OOSB relays. Disabling of these relays could lead to tripping during stable power swings causing an increased reliability risk. OOSB relays provide increased security by preventing relays from tripping for stable power swings. Preventing the tripping of transmission lines during these types of disturbances increases the reliability of the BES. The SAR recommends removing Requirement R2 because it has been interpreted to restrict the setting of OOSB elements making compliance with PRC-026 more difficult.

The SAR also recommends removing Attachment A exclusion 2.3. This exclusion is no longer needed and that exclusion has contributed to the confusion surrounding R2. Attachment A exclusion 2.3 has been interpreted as being in conflict with R2.

Summary
The SPCS developed a PRC-023-4 SAR and requested NERC Planning Committee review in December 2018. The SAR was revised based on the comments received and is seeking endorsement to submit the SAR to the Standards Committee.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Authorization Request (SAR)

Complete and please email this form, with attachment(s) to: sarcomm@nerc.net

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	Revisions to PRC-023-4		
Date Submitted:	February XX, 2020		
SAR Requester			
Name:	Jeff Iler, Chair & Bill Crossland, Vice Chair (on behalf of)		
Organization:	NERC System Protection and Control Subcommittee		
Telephone:	Jeff: (614) 933-2373 Bill: (216) 503-0600	Email:	Jeff: jwiler@aep.com Bill: bill.crossland@rfirst.org
SAR Type (Check as many as apply)			
☐ New Standard ☒ 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)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☒ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☐ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
Requirement R2, in PRC-023-4, requires applicable functional entities to set their Out of Step Blocking[1] (OOSB) elements to allow tripping for faults during the loading conditions prescribed by Requirement R1. A requirement to allow tripping in a Standard whose intent is to block tripping, has led to some entities disabling their OOSB relays. Disabling of these relays could lead to tripping during stable power swings causing an increased reliability risk. OOSB relays provide increased security by preventing relays from tripping for stable power swings. Preventing the tripping of transmission lines during these types of disturbances increases the reliability of the BES. Requirement R2 should be removed because it has been interpreted to restrict the setting of OOSB elements making compliance with PRC-026 more difficult. Attachment A exclusion 2.3 should also be removed. This exclusion is no longer needed and that exclusion has contributed to the confusion surrounding R2. Attachment A exclusion 2.3 has been			

[1] The term power swing blocking (PSB) is also used by industry to describe these elements

Requested information
interpreted as being in conflict with R2. Both R2 and Attachment A exclusion 2.3 are not needed in the Standard.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
The purpose of the proposed project provides a reliability-related benefit by eliminating PRC-023-4 Requirement R2. This will eliminate entities disabling their OOSB elements unnecessarily. It will remove an unnecessary exclusion (Attachment A – 2.3) for relays that no longer need an exclusion.
Project Scope (Define the parameters of the proposed project):
The scope includes: • Retire Requirement R2. • Remove Attachment A, Item 2.3 exclusion with regard to the use of protection systems during stable power swings. • Make comporting changes to the standard as needed to address the retirement of Requirement R2 and to remove Attachment A, Item 2.3 exclusion. • Ensure that removing the Item 2.3 exclusion does not overlap or create a gap with intent of PRC-026 – Relay Performance During Stable Power Swings. • Making any administrative non-substantive corrections. • Modify the Supplemental Technical Reference Document, "Determination and Application of Practical Relaying Loadability Ratings Version 1", referenced in PRC-023-4, as needed to address the retirements and removal. Specifically, the Out of Step Blocking section.
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[2] 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):
The PRC-023 standard is about setting protective relays so they do not limit transmission loadability, meaning they do not trip unnecessarily during heavy loading conditions while still being capable of detecting all fault conditions.[3] The intent of Requirement R2 is to ensure out-of-step blocking (OOSB) elements allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability. Requirement R2 is about ensuring OOSB elements allow blocked relay elements to trip reliably (i.e., if a three-phase fault occurs while OOSB is asserted) and not about ensuring protection systems do not limit transmission loadability. OOSB elements differentiate between power swings and three-phase faults. During a power swing, a OOSB element will typically block phase distance elements (i.e., Zone 1 & Zone 2 phase distance elements) from tripping. According to Requirement R2, a OOSB element must unblock the blocked phase distance elements for faults that occur

[2] 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.

[3] PRC-023-4, Purpose: "Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults."

Requested information
during the loading conditions used to set the protective relay under Requirement R1. Also in the standard, Attachment A, Item 2.3 excludes protection systems intended for protection during stable power swings and is seen as contradictory with Requirement R2 because these protection systems are associated with the use of OOSB elements, whose primary purpose is to ensure phase distance elements don't trip during stable power swings. The apparent intent of Requirement R2 is to ensure that OOSB elements don't pick up, time out, and block distance elements from tripping for three-phase faults during the loading conditions described in Requirement R1. The protection engineer must ensure reliable fault protection and has various tools in modern microprocessor based relays to ensure the dependable unblocking of tripping elements during faults. Applying the loadability criteria while ensuring reliable fault protection is already an underpinning of Requirement R1.[4] For example, an engineer can apply the use of override timers[5] that are available in modern microprocessor relays or can add such timers to existing electromechanical relay elements. An engineer can also use advanced microprocessor-based zero-setting OOSB algorithms. Applying the loadability criteria to relay settings under Requirement R1 somewhat meets the intent of Requirement R2 because Requirement R1 mandates not limiting transmission loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions. Additionally, Requirement R2 restrictively dictates the boundary setting of the OOSB element that starts the OOSB timer which has the overall effect of reducing the slip rate for which the OOSB element will correctly block. This results in decreasing the security of the protection scheme and increasing the chance that a misoperation of a distance element will occur for power swings that are faster than the allowable slip rate. Requirement R2 also impacts the ability to comply with NERC Reliability Standard PRC-026 (Relay Performance During Stable Power Swings) in that it affects the application of OOSB relaying that is integral to the purpose of PRC-026, which is "[t]o ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions". Attachment A, 2.3 was included for protection systems that intentionally trip during power swing disturbances, such as intentional islanding schemes. Florida was cited as an example of where these schemes were employed. Research has indicated that these schemes no longer exist and there is no need for a power swing tripping exclusion. Requirement R2 was added to PRC-023 in version 2 after filing version 1 with FERC.[6] FERC observed that Attachment A item 2 in PRC-023-1 was a requirement and that it needed to be included in the requirements section of a standard with the appropriate violation risk factors and violation severity levels.

[4] PRC-023-4, "R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability **while maintaining reliable protection of the BES for all fault conditions**. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees."

[5] OOSB relays with override timers will allow the OOSB blinder that starts the timer to be set beyond the loadability region prescribed by the standard. The OOSB relay would unblock after a predetermined delay should an unlikely three-phase fault occur.

[6] See FERC Order 733 para 244 https://www.ferc.gov/whats-new/comm-meet/2010/031810/E-5.pdf

Requested information
The original SDT included the "warning" in Attachment A item 2, with regards to OOSB, in reference to the OOSB timer. Some OOSB schemes employ an outer and an inner impedance blinder with a timer that is used to determine the rate of change of apparent impedance to differentiate between a fault (fast change) and a swing (slow change). The timer starts timing when the impedance passes through (is less than) the outer blinder. If the impedance does not pass through the inner blinder (is less than), before the timer setting, the OOSB will declare a swing and block the phase distance elements from tripping. The SDT wanted to inform entities that they could experience loading conditions that would result in an impedance that was between the OOSB blinders for a long period of time that would result in the blocking of the phase tripping elements indefinitely. This condition could exist at any time regardless of a relay loadability requirement. Therefore, this should not be a requirement associated with PRC-023. It is good engineering practice to ensure your relays will operate properly for all conditions they are expected to experience. This should not be a requirement in a relay loadability Standard. OOSB elements are included in the Relay Performance During Stable Power Swings Standard PRC-026-1. PRC-026-1 already includes the language "while maintaining dependable fault detection" in regards to OOSB supervision. Attachment A item 2.3 excludes "Protection systems intended for protection during stable power swings". This exclusion is referencing "Protection systems installed specifically to separate portions of the system that are experiencing stable power swings relative to each other in order to maintain desirable performance relative to voltage, frequency, and power oscillations"[7]. These Out of Step Tripping (OOST) protection systems are better addressed in the standard for power swings, PRC-026.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Should reduce cost to Registered Entities by eliminating the compliance monitoring of a requirement that is addressed by another standard. Revising the exemption should not have a significant impact on cost.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g*. Dispersed Generation Resources):
Transmission facilities that use OOSB functionality and that experience significant oscillations (i.e., power swings) has the benefit of ensuring the system remains intact where separation of portions of the transmission system could occur due to power swings.
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):
Transmission Owner, Generator Owner, and Distribution Provider

[7] See Project 2010-13.1 Phase 1 of Relay Loadability: Transmission Draft 1 Relay Loadability Standard Consideration of Comments https://www.nerc.com/pa/Stand/Project%202010131%20Phase%201%20of%20Relay%20Loadability%20Trans/Consider_Comments_1st_Draft_Relay_Loadability_Std_09Jan07.pdf

Requested information
Do you know of any consensus building activities[8] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
N/A
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)?
PRC-026 – Relay Performance During Stable Power Swings (Note: Project 2015-09 – Establish and Communicate System Operating Limits is proposing modifications to PRC-026 due to revisions to the definition of System Operating Limit).
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.
N/A

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.
☐	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	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes

[8] 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.

Market Interface Principles	
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
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.	Yes

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
N/A	

For Use by NERC Only

SAR Status Tracking (Check off as appropriate)	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template

Reliability Guideline: Gas and Electrical Operational Coordination Considerations

Action
Accept posting for 45-day public comment period.

Background
Reliability Guideline: Gas and Electrical Operational Coordination Considerations was approved by the NERC Operating Committee on December 13, 2017. Coordination of operations between the gas and electric industries has become increasingly important over the course of the last decade. The electric power sector's use of gas, specifically natural gas-fired generation, has grown exponentially in many areas of North America due to increased availability of gas, potentially more competitive costs in relation to other fuels and a move throughout the industry to lower emissions to meet environmental goals. With increased growth in gas usage comes greater reliance and associated risk due to the dependency that each industry now has on the other. The operational impact of these dependencies requires gas and electric system operators to actively coordinate planning and operations. The goal of the coordination is to ensure that both the gas and electric systems remain secure and reliable during normal, abnormal and emergency conditions.

Per the RSTC Charter, all Reliability Guidelines are to be reviewed on a three-year cycle.

Summary
The Reliability Guideline: Gas and Electrical Operational Coordination Considerations was revised by the Operating reliability Subcommittee and endorsed at its September 2020 meeting. The Operating Reliability Subcommittee and Electric-Gas Working Group will coordinate a comment period, review and update for the Reliability Guideline. These two groups are seeking approval to post the document for a 45-day public comment period.

Reliability Guideline

Gas and Electrical Operational Coordination Considerations

Applicability:

Reliability Coordinators (RCs), Balancing Authorities (BAs), Transmission Operators (TOPs)
Generator Owners (GOs), and Generator Operators (GOPs)

Preamble

It is in the public interest for the North American Electric Reliability Corporation (NERC) to develop guidelines that are useful for maintaining or enhancing the reliability of the Bulk Electric System (BES). The Technical Committees of NERC- the Operating Committee (OC), the Planning Committee (PC) and the Critical Infrastructure Protection Committee (CIPC) – are, per their charters authorized by the NERC Board of Trustees (Board) to develop Reliability (OC and PC) and Security (CIPC) Guidelines. Guidelines establish voluntary codes of practice for consideration and use by BES users, owners, and operators. These guidelines are developed by the technical committees and include the collective experience, expertise and judgment of the industry. Reliability guidelines do not provide binding norms or create parameters by which compliance to standards is monitored or enforced. While the incorporation and use of guideline practices is strictly voluntary, the review, revision, and development of a program using these practices is strongly encouraged to promote and achieve the highest levels of reliability for the BES. Nothing in this guideline negates obligations or requirements under an entity's regulatory framework (local, state or federal) and all parties must take those requirements into consideration when developing any of the guidance detailed herein.

Background and Purpose

Coordination of operations between the gas and electric industries has become increasingly important over the course of the last decade. The electric power sector's use of gas, specifically natural gas-fired generation, has grown exponentially in many areas of North America due to increased availability of gas, potentially more competitive costs in relation to other fuels and a move throughout the industry to lower emissions to meet environmental goals. With increased growth in gas usage comes greater reliance and associated risk due to the dependency that each industry now has on the other. The operational impact of these dependencies requires gas and electric system operators to actively coordinate planning and operations. The goal of the coordination is to ensure that both the gas and electric systems remain secure and reliable during normal, abnormal and emergency conditions. This guideline attempts to provide a set of principles and strategies that may be adopted should the region in which you operate require close coordination due to increased dependency. This guideline does not apply universally, and an evaluation of your area's unique needs is essential to determine which principles and strategies you apply. The guideline principles and strategies may be applied by RCs, BAs, TOPs, GOs and GOPs in order to ensure reliable coordination with the gas industry. Finally, the document focuses on the areas of preparation, coordination, communication and intelligence that may be applied in order to coordinate gas-electric utility operations and minimize reliability-related risk.

Guideline Content:

A. Establish Gas and Electric Industry Coordination Mechanisms

B. Preparation, Supply Rights, Training and Testing

C. Establish and Maintain Open Communication Channels

D. Intelligence and Situational Awareness

E. Summary

A. Establish Gas and Electric Industry Coordination Mechanisms

- Establish Contacts
  - An essential part of any coordination activity is the identification of participants. For gas and electric coordination, this could involve the identification of the natural gas pipeline, gas suppliers and Local Distribution Companies (LDC) gas entities as well as gas industry operations staff within the electric footprint boundaries and in some instances beyond those boundaries. Once contacts among these participants are established, additional coordination activities can begin. Gas industry trade organizations, such as the Interstate Natural Gas Association of America, Natural Gas Supply Association, American Gas Association or a regional entity such as the Northeast Gas Association may be able to aid in development of operational contacts and the establishment of coordination protocols. These contacts should be developed for long and short term planning/outage coordination as well as near term and real-time operations. The contacts should include both control room operating staff contacts as well as management. Establishing and maintaining these contacts is the most important aspect of gas and electric coordination. Past lessons learned have taught the industry that the first call you make to a gas transmission pipeline or LDC should not be during abnormal or emergency conditions.
- Communication Protocols
  - Once counterparts are identified in the gas industry, communications protocols will need to be established within the regulatory framework of both energy sectors looking to coordinate and share information. The Federal Energy Regulatory Commission issued a Final Rule under Order No. 787 allowing interstate natural gas pipelines and electric transmission operators to share non-public operational information to promote the reliability and integrity of their systems. Since the inception of this rule and the subsequent incorporation of those rules into the associated tariffs, followed by the appropriate confidentiality agreements, gas and electric entities have been able to freely share operational data. Data that could be shared to improve operational coordination may include but is not necessarily limited to the following:
    - Providing detailed operational reports to the gas pipeline operators by specific generating assets, operating on specific pipelines, which specify expected fuel burn by asset, by hour over the dispatch period under review. It is important to convert dispatch plans from electric power (MWh) to gas demand (dekatherms/day) when conveying that information to gas system operators.

- Combining the expected fuel to be used by asset on each pipeline in aggregate to provide an expected draw on the pipeline by generation connected to that pipeline on an hourly basis and on a gas and electric day basis.

- Exchanging real-time operating information in both verbal and electronic forms (e.g., pipeline company informational postings) of actual operating conditions on specific assets on specific pipelines.
- Outage planning for elements of significance to include sharing detailed electric and gas asset scheduling information on all time horizons and coordinating outages of those assets to ensure reliability on both the gas and electric systems. This coordination should include if possible face-to-face coordination meetings.
- Sharing normal, abnormal and emergency conditions in real-time and ensuring each entity understands the implications to their respective systems. This should include gas and electric entities proactively reaching out to the operators of stressed gas systems to discuss the impacts, adverse or otherwise, of their expected or available actions. Under extreme gas system operating conditions, understand the direct impacts to electric generation assets when gas pipelines are directed under force majeure conditions.
- The sharing of non-public operating information between the electric operating entity and LDC, intrastate pipelines, and gathering pipelines is not covered under FERC Order 787. For this reason, individual communication and coordination protocols should be considered with each LDC and intrastate pipelines within the footprint of the operating entity. Understanding the conditions under which an LDC or intrastate pipeline would interrupt gas-fired generation is of particular importance and incorporating this information into operational planning will assist in identification of potential at-risk generation. Setting up electronic/email alerts from each LDC or intrastate pipeline as to the potential declaration of interruptions is one key means of real time identification of potential loss of generation behind the LDC city gate or meter station on an intrastate pipeline.

- Coordinating Procurement Time Lines
  - Operating entities may want to consider changing next day operating plan scheduling practices to align more efficiently with gas day procurement cycles. The gas and electric industries operate on differing timelines for the Day Ahead planning processes and in real-time, with the electric day on a local midnight to midnight cycle. The gas industry process operates on a differing timeline with the operating day beginning at 9 a.m. Central Clock Time and uniform throughout North America. This difference in operating days can lead to inefficient scheduling of natural gas to meet the electric day demands. In many instances throughout North America, the electric industry has moved the development and publishing of unit commitments and next day operating plans in order to ensure that generation resources have the ability to procure and nominate natural gas more efficiently to better meet the scheduling timelines of the gas industry. In addition, the gas industry has adjusted some of its nomination and scheduling practices to allow for more efficient scheduling that meets the needs of the electric system. Coordinating and modifying scheduling practices using more effective time periods may allow

for a higher level of pipeline utilization, but more importantly, may provide the early identification of constraints that could require starting gas generation with alternate fuels, or using non-gas-fired facilities for fuel diversity to meet the energy and reserve needs of the electric system.

- Identification of Critical Gas System Components and Dual-fuel Supplier Components
    - It is essential gas and electric operating entities coordinate to ensure that critical natural gas pipelines, compressor stations, LNG, storage, natural gas processing plants, and other critical gas system components should not be subject to electric utility load shedding in general but more specifically Under Frequency and or Manual Load shedding programs.
        - Electric transmission and distribution owners are capable of interrupting electrical load either automatically through under frequency load shedding relays installed in substations throughout North America or via manual load shedding ordered by RCs, BAs and or TOPs via SCADA. These manual and automatic load shedding protocols are part of every entity's emergency procedures. Entities should try to ensure critical gas sector infrastructure is not located on electrical circuits that are subject to the load shedding described above. Electric operators should establish contact with the gas companies operating within its jurisdiction to compile a list of critical gas and other fuel facilities which are dependent upon electric service for operations. This list should also consider the availability of backup generation at critical gas facilities. Once the list is compiled, a comprehensive review of load shedding procedures/schemas/circuits should be done to verify that critical infrastructure is not connected to or located on any of those predefined circuits. This review should be considered for evaluation at least annually. The best practice in this area is to try and ensure that these facilities are not included in the initial under frequency or manual load shedding protocols at the outset.
    - In a similar manner, it may be appropriate to coordinate with secondary fuel (e.g., diesel or fuel oil, onsite LNG) suppliers to ensure that any necessary critical terminals, pump stations, and other critical components are not subject to electric utility load shedding programs in general and more specifically Under Frequency and or Manual Load shedding programs. This is especially appropriate if adequate on-site fuel reserves are not guaranteed and just-in-time fuel delivery practices are required.

- Operating Reserves
    - The electric industry may want to consider adjustments to operating reserve or capacity requirements to better reflect the increased reliance on natural gas for the generation fleet. For instance, if the loss of a fuel forwarding facility has the ability to result in an instantaneous or near instantaneous electric energy loss, that contingency should be reflected in the reserve or capacity procurement for the operating day. In addition, some electric operators are considering the implementation of a risk-based operating reserve protocol that increases or decreases the amount of operating reserve procured based upon the risks identified to both the gas and electric system.

B. Preparation, Supply Rights, Training and Testing

- Assessments
  - Preparing the gas and electric system for coordinated operations benefits from up front assessments and activities to ensure that when real-time events occur, the system operators are prepared for and can effectively react. Preparation activities that may be considered include the following:
    - Developing a detailed understanding of where and how the gas infrastructure interfaces with the electric industry including:
      - Identifying each pipeline (interstate and intrastate) that operates within the electric footprint and mapping the associated electric resources that are dependent upon those pipelines.
      - Identifying the level and quantity of pipeline capacity service (firm or interruptible; primary/secondary) and any additional pipeline services (storage, no-notice, etc.) being utilized by each gas-fired generator.
      - Developing a model of and understanding the non-electric generation load that those pipelines and LDCs serve and will protect when gas curtailments are needed.
      - Identifying gas single element contingencies and how those contingencies will impact the electric infrastructure. For instance, although most gas side contingencies will not impact the electric grid instantaneously, they can be far more severe than electric side contingencies over time because gas side contingencies may impact several generation facilities. When identifying gas system contingencies, the electric entity should consider what the gas operator will do to secure its firm customers. This could include the potential that the gas system will invoke mutual aid agreements with other interconnected pipelines and this may involve curtailment of non-firm electrical generation from the non-impacted pipeline to aid the other.
      - Understanding how gas contingencies may interact with electric contingencies during a system restoration effort.
      - An additional example of appropriate actions to consider as part of the assessment phase of preparation is provided as a Natural Gas Risk Matrix[1].
- Emergency Procedure Testing and Training
  - Consider the development of testing and training activities to recognize abnormal gas system operating conditions and to support extreme gas contingencies such as loss of compressor stations, pipelines, pipeline interconnections, large LNG facilities, which can result in multiple generator losses over time. Particular attention should be focused on any gas related contingency that may result in an instantaneous generation loss.

[1] https://www.misoenergy.org/StakeholderCenter/CommitteesWorkGroupsTaskForces/ENGCTF/Pages/home.aspx

- Consider the addition of electric and natural gas coordination and interdependencies training to educate and exercise RCs, BAs, TOPs, and GOPs during potentially adverse natural gas supply disruptions.
- If voltage reduction capability exists within your area, practical testing and training should be considered as part of seasonal or annual work plans.
- The use of manual firm load shedding may be required for beyond criteria extreme gas and or electric contingencies. Consideration should be given to practicing the use of manual load-shedding in a simulated environment. These simulations should also be used as part of recurring system operator training at a minimum. The use of tabletop exercises can be a valuable training aid, but wherever possible, consideration should be given to using an advanced training simulator that employs the same tools the operators would use to accomplish the load shedding tasks.
- Consider the development of and drill on internal communication protocols specific to potential natural gas interruptions.

- Generator Testing
  - Consideration should be given to adopting generator testing requirements for dual fuel auditing. Some items to consider when establishing a dual fuel audit program are:
    - How often should the audits be conducted and under what weather and temperature conditions.
    - Verify sufficient alternate fuel (e.g., fuel oil) inventory to ensure required generation response and output. As part of this assessment, ensure that the stored fuel is fully burnable as well since the full volume of the tank may not be pumpable at very low inventories.
    - Capacity reductions on alternate fuels.
    - Understanding the exact time it takes to startup, switch to alternate fuel, ramp to and operate at full capacity, ramp down and resource shut down. Additional consideration should be given for those assets which require a shutdown in order to swap to an alternate fuel source.
    - The operating entity should consider any environmental constraints the generator under test must meet in order to swap to and operate on the alternate fuel.
- Capacity and Energy Assessments
  - Consideration should be given to the development of forward looking capacity analyses with which the electric industry is familiar but applying the impacts of fuel restrictions that may occur due to pipeline constraints or other fuel delivery constraints such as LNG shipments or liquid fuel delivery considerations. In order to conduct these types of assessments, the analysis needs to consider the LDC loads within the region. The weather component of the assessment should consider normal, abnormal and extreme conditions (i.e., Gas Design Day, which is the equivalent to the highest peak that the pipeline was designed for). This capacity assessment can be on several time horizons including; Real-time, Day Ahead, Month Ahead and Years into the future.

These assessments should consider pipeline maintenance, known future outages, construction and expansion activities as well as all electric industry considerations, including known or potential regulatory changes, which are normally analyzed.

- In addition to a capacity assessment that represents only a single point in time, consideration should be given to the development of a seasonal, annual or multiannual energy analysis that uses fuel delivery capability/limitations as a component. Such assessments can be scenario based, simulate varied weather conditions over the course of months, seasons and/or years, and consider the same elements as discussed in the capacity analysis. The output of the assessments should determine whether there is the potential for unserved energy and/or determine the ability to provide reserves over the period in question.

- Winter Readiness Reviews
  - Recent system events have magnified the need to ensure that seasonal awareness and readiness training is completed within the electric industry including System Operators, Generator Operators and Transmission Operators. Seasonal readiness training for winter weather could include reviews and training associated with dual fuel testing, emergency capacity and energy plans, weather forecasts over the seasonal period, fuel survey protocols and storage readiness. Other areas that require attention in winter readiness reviews include reviewing and setting specific operational expectations on communications protocols. Finally, any winter readiness seminars should include individual generator readiness such as ensuring adequate fuel arrangements are in place for unit availability, adequate freeze protection guidelines are in place, understanding access to primary and secondary fuels and testing to switch to alternate fuels, ensuring all environmental permitting is in place for the fuel options available to the asset, and making sure that the Balancing and Transmission Operators are kept apprised of the unit availability.
- Extreme Weather Readiness Reviews
  - Seasonal readiness reviews for extreme summer weather events (e.g., Gulf of Mexico hurricane) could include response to potential natural gas supply limitations and corresponding decreases in natural gas deliveries that may impact electric generation. Many of the same benefits as winter readiness exercises can be realized with the added benefit of exercises under summer operating conditions when electric loads are higher than winter loads.

C. Establish and Maintain Open Communication Channels

- Industry Coordination
  - In the long and short term planning horizons, regularly scheduled meetings between the gas and electric industries should be held to discuss upcoming operations including outage coordination, industry updates, project updates and exchange of contact information.
  - Operating entities should consider the development of a coordinated and annually updated set of operational and planning contact information for both the gas and electric industries. This information should include access to emergency phone numbers for management contacts as

well as all control center real-time and forecaster desks for use in normal, abnormal and emergency conditions.

- Gas and Electric emergency communication conference call capability should be considered between the industries such that operating personnel can be made available from both industries immediately, including off hours and within the confines of the individual confidentiality provisions of each entity. Electric sector personnel should periodically monitor pipeline posted information and notices.

- Emergency Notifications to Stakeholders
  - Operating Entities may want to consider proactive notifications to stakeholders of abnormal and or emergency conditions on gas infrastructure to ensure widespread situational awareness and obligations associated with dispatch relationships in the electric sector. An example of a notification used for generators in New England appears below:

1. Notices Indicating Abnormal and/or Emergency Conditions on the Pipeline Infrastructure Serving Generators

NOTE

Notices indicating abnormal and/or emergency conditions on the pipeline infrastructure serving a Generator in the ISO RCA/BAA could come in the form of, but **not** limited to, Operational Flow Orders, Imbalance Warnings or even a verbal notification.

A) When electronic and or verbal notices indicating abnormal and or emergency conditions on the pipeline infrastructure serving a Generator in the ISO RCA/BAA are received, the Forecaster notifies the Operations Forecast and Scheduling Supervisor (or designee)

(1) The Forecaster reviews this information and depending upon the severity of the condition may pass the publicly available information along by drafting an email and submitting it to Customer Service for dissemination to each applicable Generator Designated Entity (DE) management contact(s) and/or Lead Market Participant (MP) contact(s).

NOTE

The following guideline or one tailored to the current situation can be used as a template for drafting this notification;

"ISO-NE has received the following information via the publicly available notices published by the gas pipelines:

(Insert Notice, such as Operational Flow Order or Force Majeure, etc.)

"Because of this situation, it is critical that each applicable Generator DE or Lead MP provide ISO-NE with up to date and reliable estimates of each Generator current and future capabilities including the ability to have fuel for a Generator under their control. This includes immediately reporting any information that may prevent a Generator from operating in accordance with submitted offer data, including, but **not** limited the following:

- Planned, Maintenance and or Forced outages of the Generator facilities as soon as that information is available
- Immediate reporting of any updates to outages including overruns and or early returns to service of the Generator facilities
- Any high risk activities at a Generator location that may reduce its capability or place the capability at risk
- Any fuel reductions or outages that may limit a Generator's ability to perform in any way
- Any changes to any operating limits of a Generator which must reflect the most accurate and up to date information available
- Any changes at all in a Generator ability to follow dispatch instructions including manual response rates, ability to provide reserve, ability to provide energy, and/or ability to provide capacity
- Any changes in projected Generator self schedules

Depending upon the level of severity and risk exposure, these written notifications and a means to communicate them may need to be followed up with direct verbal communications.

- Emergency Communication Protocols in the Public and Regulatory Community
  - Most every electric operating entity has long standing capacity and energy emergency plans in place that focus on public awareness, abnormal and emergency communications as well as appeals for conservation and load management. However, as the gas and electric industry become further dependent, considerations should be made for both industries to coordinate for extreme circumstances. Gas and electric operators in coordination with public officials, including relevant regulatory communities, may find situations where the energy of both the gas and electric sector is required to be reduced in order to preserve the reliability of both.

While these types of efforts are still in their infancy they should be explored depending upon the particular circumstances of each entity's Region.

D. Intelligence and Situational Awareness

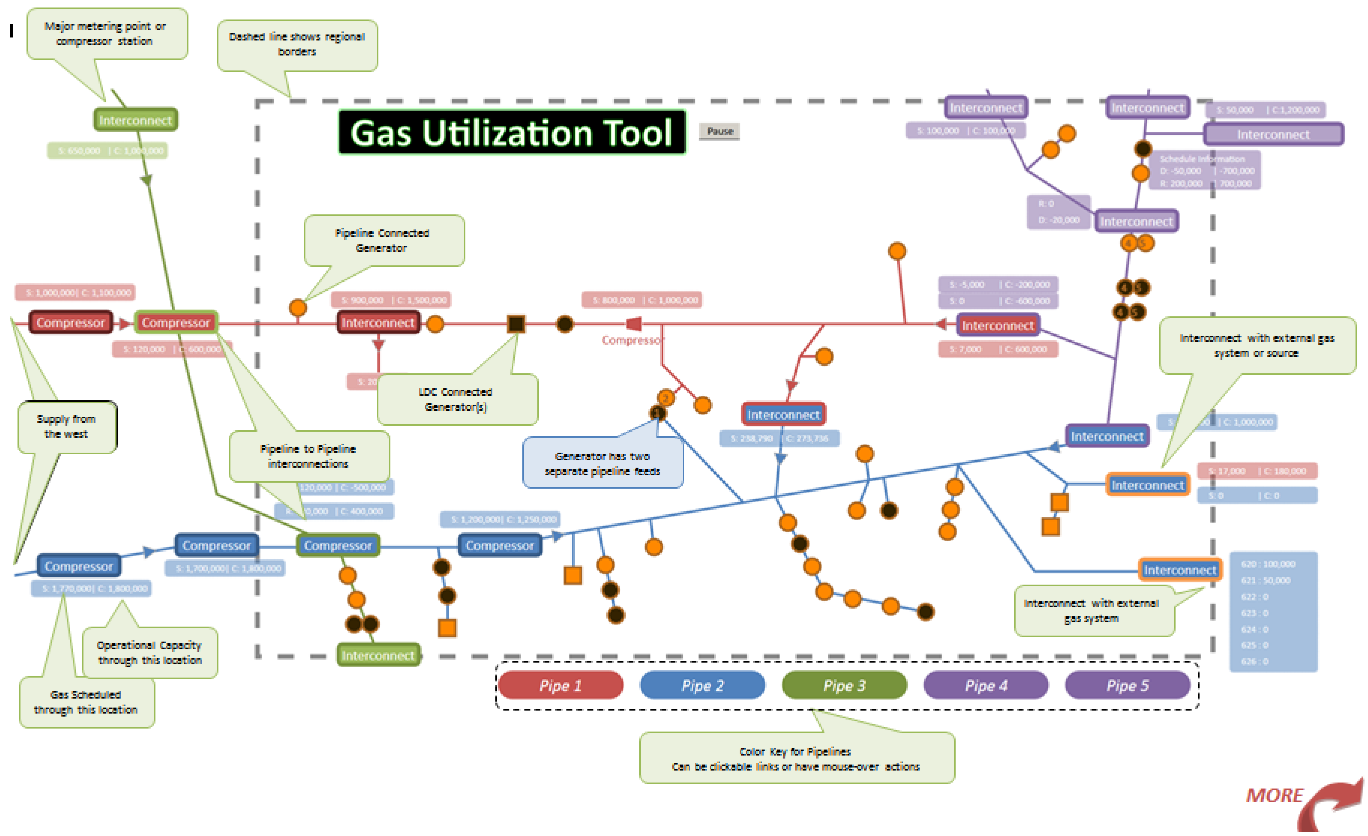
- Fuel Surveys and Energy Emergency Protocols
  - Energy emergency procedures and fuel surveys can be important tools in understanding the energy situation in a region. The surveys can be used to determine energy adequacy for the region's electric power needs and for the communications and associated actions in anticipation or declaration of an energy emergency[2]. Interestingly, the fuel surveys[3][4] will most likely focus on the fuel availability of other types of fuels if the gas infrastructure is the constrained resource.
- Fuel Procurement
  - Operating entities should consider evaluating each electric generator's natural gas procurement and commitment to determine fuel security for the operating day.
    - The electric operating entity can collect publicly available pipeline bulletin board data and compare the gas procurement for individual generators against the expected electric operations of the same facility in the current or next day's operating plan. An example of this type of data collection appears below with the data helping to determine if enough fuel is available to meet an individual plant or in aggregate an entire gas fleet's expected operation for the current or future day. The report can indicate whether a fuel surplus or deficit exists by asset or for an entire pipeline. If sufficient gas has not been nominated and scheduled to the generator meter, assessments can be done to determine the impact on system operations and the operating staff may call the generator to inquire as to whether the intention is to secure the requisite gas supply to match its expected dispatch plus operating reserve designations.

[2] Energy emergency example: https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op21/op21_rto_final.pdf
[3] Seasonal survey example – See section 7.3.5 in Manual 14 http://www.pjm.com/~/media/documents/manuals/m14d.ashx
[4] Real-time survey example – See section 6.4 of Manual 13http://www.pjm.com/~/media/documents/manuals/m13.ashx

Plant	MWh Burned So Far	MWh Before Midnight	MWh After Midnight	MWh Scheduled	MWh Surplus	Gas Scheduled
1	2201	169	1932	4493	191	34600
2	777	0	663	0	(1440)	0
3	1910	0	901	2849	38	20700
4	2131	0	0	2736	605	20028
5	5903	403	0	7706	1400	53800
6	2369	0	798	3097	(70)	22500
7	1253	0	350	93	(1510)	1000
8	2402	185	1850	5129	692	45500
9	0	0	0	28	28	300
10	3	0	525	0	(528)	0
11	0	0	0	0	0	0
12	1	0	0	0	(1)	0
13	4	0	0	0	(4)	0
14	5077	389	2864	9591	1261	65621
15	3394	215	0	3347	(262)	25048
16	3554	550	6017	221	(9900)	1500
17	10639	797	4157	17418	1825	126540
18	7249	545	3892	11096	(590)	80813
19	972	45	1066	9	(2074)	100
20	0	0	0	0	0	0
21	0	0	0	0	0	0
22	6294	0	2476	1643	(7127)	17471
23	2758	0	1209	3944	(23)	30000
24	2400	250	1250	579	(3321)	5000
25	4998	0	2317	6917	(398)	52595
26	3208	250	1189	0	(4647)	0
27	2434	0	0	2747	313	23512
28	4222	0	0	5634	1412	42963
29	2121	0	0	2343	222	20000
30	0	0	0	0	0	0
31	1141	86	860	2344	257	27000
32	0	0	0	0	0	0
33	1071	0	3490	5037	476	38325

Varying configurations of generator gas supplies can quickly complicate reports. Efforts should be made prior to the development of such reporting tools to ensure that all facets of gas scheduling can be displayed. Not all scheduled gas data will be publically available, especially when dealing with LDC- and intrastate-connected generators. Generators are often supplied by multiple pipelines simultaneously and may change supply sources based on daily natural gas prices. If possible, the electric operating entity should list its range of contractual arrangements with the natural gas sector such as firm supply, no-notice storage, etc.

- Gas System Visualization
  - Several Reliability Coordinators have developed visualization tools to provide scheduling and real-time operations staff with situational awareness that ties the gas and electric infrastructure together at their common point of operation. What follows is an example of one such tool that has been made generic for the purposes of the illustration. The bubbles in the tool indicate the functionality available to the user with notes that follow.



Notes:

- The display is updated automatically or on demand. Historical data is available for 30 days in the past. Can be expanded to more days or specific days.
- Generators are clickable and additional information is provided via popup message.
- Pipeline Color Key is clickable and navigates to the specific pipeline EBB.
- All of the values are in MMBtu for the gas day. When operational capacity changes, the display automatically updates based on EBB posted capacity and schedule values.
- Schedules are for the GAS DAY, rolling over at 10:00. (e.g. Gas Day 4/15/2016 starts at 10 am on 4/15 and ends at 4/16 at 10am.)
- These are SCHEDULES and may not reflect the physical flow of gas. Schedules may not match due to differences in scheduling cycles or accounting methods used by different companies.
- Just because there's room for gas to flow at a throughput meter or cross connect, doesn't mean there's gas there to move through.
- *Delivery* is gas leaving the pipeline. *Receipt* is gas entering the pipeline.
- Schedule Badges show Delivery and Receipt where there can be bi-directional scheduling and Schedule where there is not bi-directional scheduling. Most of the schedule badges show a Capacity value as well.
  - You have to net multiple schedules to derive an estimated final schedule at a location
- Some generators have a single meter to their facility with shared ownership. Through that meter, gas can be scheduled via Pipe 4 or Pipe 5.
- Many generators have multiple connections to separate pipelines and that can be displayed as well
- Meters with zero gas scheduled have darkened icons on this display

Possibilities:

- Real-time power information for the generators as well as how much gas has been consumed and how much remains
- OFO display information based on EBB postings
- Graphical trending of any value you can select

E. Summary

The transformation in the mix of fuel sources used to power electric generation throughout North America and in particular, the continued increase in the use of natural gas has naturally led to the coordination processes discussed in the preceding guideline. The guideline should serve as a reference document that NERC functional entities may use as needed to improve and ensure BES reliability and is based upon actual lessons learned over the last several years as natural gas has developed into the fuel of choice due to its availability and economic competitiveness. The document focuses on the areas of preparation, coordination, communication, and intelligence that may be applied to improve gas and electric coordinated operations and minimize interdependent risks. Each entity should assess the risks associated with this transformation and apply a set of appropriate processes and practices across its system to mitigate those risks. The guidance is not a "one size fits all" set of measures but rather a list of principles and strategies that can be applied according to the circumstances encountered in a particular system, Balancing Authority, generator fleet or even an individual Generator Operator.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Reliability Guideline

Gas and Electrical Operational Coordination Considerations

Commented [A1]: With edits by IRC EGCTF

Applicability:

Reliability Coordinators (RCs), Balancing Authorities (BAs), Transmission Operators (TOPs) Generator Owners (GOs), and Generator Operators (GOPs)~~RCs, BAs, TOPs, GOs and GOPs~~

Preamble

It is in the public interest for the North American Electric Reliability Corporation (NERC) to develop guidelines that are useful for maintaining or enhancing the reliability of the Bulk Electric System (BES). The Technical Committees of NERC- the Operating Committee (OC), the Planning Committee (PC) and the Critical Infrastructure Protection Committee (CIPC) – are, per their charters authorized by the NERC Board of Trustees (Board) to develop Reliability (OC and PC) and Security (CIPC) Guidelines. Guidelines establish voluntary codes of practice for consideration and use by BES users, owners, and operators. These guidelines are developed by the technical committees and include the collective experience, expertise and judgment of the industry. Reliability guidelines do not provide binding norms or create parameters by which compliance to standards is monitored or enforced. While the incorporation and use of guideline practices is strictly voluntary, the review, revision, and development of a program using these practices is strongly encouraged to promote and achieve the highest levels of reliability for the BES. Nothing in this guideline negates obligations or requirements under an entity's regulatory framework (local, state or federal) and all parties must take those requirements into consideration when implementing ~~developing~~ any of the guidance detailed herein.

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Background and Purpose

Coordination of operations between the gas and electric industries has become increasingly important over the course of the last decade. The electric power sector's use of gas, specifically natural gas-fired generation, has grown exponentially in many areas of North America due to increased availability of gas, potentially more competitive costs in relation to other fuels and a move throughout the industry to lower emissions to meet environmental goals. With increased growth in gas usage comes greater reliance and associated risk due to the dependency that each industry now has on the other. The operational impact of these dependencies requires gas and electric system operators to actively coordinate planning and operations. The goal of the coordination is to ensure that both the gas and electric systems remain secure and reliable during normal, ~~abnormal~~ and emergency conditions. This guideline attempts to provide a set of principles and strategies that may be adopted should the region in which you operate require close coordination due to increased dependency. This guideline does not apply universally, and an evaluation of your area's unique needs is essential to determine which principles and strategies you apply. The guideline principles and strategies may be applied by RCs, BAs, TOPs, GOs and GOPs in order to ensure reliable coordination with the gas industry. Finally, the document focuses on the areas of preparation, coordination, communication and ~~intelligence~~ gathering & sharing information that may be applied in order to coordinate gas-electric utility operations and minimize reliability-related risk.

Guideline Content:

A. Establish Gas and Electric Industry Coordination Mechanisms

B. Preparation, Supply Rights, Training and Testing

C. Establish and Maintain Open Communication Channels

D. ~~Intelligence~~ Gathering, Sharing Information and Situational Awareness

E. Summary

A. Establish Gas and Electric Industry Coordination Mechanisms

- Establish Contacts
  - An essential part of any coordination activity is the identification of participants. For gas and electric coordination, this could involve the identification of the natural gas interstate/intrastate pipelines, gas suppliers and Local Distribution Companies (LDC) ~~gas entities~~ as well as gas industry operations staff within the electric footprint boundaries and in some instances beyond those boundaries. Once contacts among these participants are established, additional coordination activities can begin. Gas industry trade organizations, such as the Interstate Natural Gas Association of America, Natural Gas Supply Association, American Gas Association or a regional entity such as the Northeast Gas Association may be able to aid in development of operational contacts and the establishment of coordination protocols. These contacts should be developed for long and short term planning/outage coordination as well as near term and real-time operations. The contacts should include both control room operating staff contacts as well as management. Establishing and maintaining these contacts is the most important aspect of gas and electric coordination. Past lessons learned have taught the industry that the first call you make to a gas transmission pipeline or LDC should not be during ~~abnormal or~~ emergency conditions.
- Communication Protocols
  - Once counterparts are identified in the gas industry, communications protocols will need to be established within the regulatory framework of both energy sectors looking to coordinate and share information. The Federal Energy Regulatory Commission issued a Final Rule under Order No. 787 allowing interstate natural gas pipelines and electric transmission operators to share non-public operational information to promote the reliability and integrity of their systems.

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Since the inception of this rule and the subsequent incorporation of those rules into the associated tariffs, followed by the appropriate confidentiality agreements, gas and electric entities have been able to freely share operational data. Data that could be shared to improve operational coordination may include but is not necessarily limited to the following:

- o Providing detailed operational reports to the gas pipeline operators by specific generating assets, operating on specific pipelines, which specify expected fuel burn by asset, by hour over the dispatch period under review. It is important to convert dispatch plans from electric power (MWh) to gas demand (in terms of gas units/time such as dekatherms/day or MMcf/hour) when conveying that information to gas system operators.
- o Combining the expected fuel to be used by asset on each pipeline in aggregate to provide an expected draw on the pipeline by generation connected to that pipeline on an hourly basis and on a gas and electric day basis.

- Exchanging real-time operating information in both verbal and electronic forms (e.g., pipeline company informational postings) of actual operating conditions on specific assets on specific pipelines.
- Outage planning for elements of significance to include sharing detailed electric and gas asset scheduling information on all time horizons and coordinating outages of those assets to ensure reliability on both the gas and electric systems.
- ~~This coordination should include if~~Scheduling ~~possible~~ face-to-face coordination meetings~~.~~ to discuss a range of topics including but not limited to outage coordination, proposed electric/gas market rule changes, upcoming gas generator additions, pending electric retirements/repowers, enhancements/modifications to gas/electric coordination tools, gas pipeline infrastructure changes, near/long-term seasonal forecasts and load shape changes.
- Sharing normal, ~~abnormal~~ and emergency conditions in real-time and ensuring each entity understands the implications to their respective systems. This should include gas and electric entities proactively reaching out to the operators of stressed gas systems to discuss the impacts, adverse or otherwise, of their expected or available actions. Under extreme gas system operating conditions, understand the direct impacts to electric generation assets when gas pipelines are directed under force majeure conditions.
- The sharing of non-public operating information between the electric operating entity and LDC, intrastate pipelines, and gathering pipelines is not covered under FERC Order 787. For this reason, individual communication and coordination protocols should be considered with each LDC and intrastate pipelines within the footprint of the operating entity. Understanding the conditions under which an LDC or intrastate pipeline would interrupt gas-fired generation is of particular importance and incorporating this information into operational procedures and planning will assist in identification of potential at-risk generation. Setting up electronic/email alerts from each LDC or intrastate pipeline as to the potential declaration of interruptions is one key means of real time identification of potential loss of generation behind the LDC city gate or meter station on an intrastate pipeline.

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- Coordinating Procurement Time Lines
  - Operating entities may want to consider changing next day operating plan scheduling practices to align more efficiently with gas day procurement cycles. The gas and electric industries operate on differing timelines for the Day Ahead planning processes and in real-time, with the electric day on a local midnight to midnight cycle. The gas industry process operates on a differing timeline with the operating day beginning at 9 a.m. Central Clock Time and uniform throughout North America. This difference in operating days can lead to inefficient scheduling of natural gas to meet the electric day demands. In many instances throughout North America, the electric industry has moved the development and publishing of unit commitments and next day operating plans in order to ensure that generation resources have the ability to procure and nominate natural gas more efficiently to better meet the scheduling timelines of the gas industry. In addition, the gas industry has adjusted some of its nomination and scheduling practices to allow for more efficient scheduling that meets the needs of the electric system.
  - Coordinating and modifying scheduling practices using more effective time periods may allow for a higher level of pipeline utilization, but more importantly, may provide the early identification of constraints that could require starting gas generation with alternate fuels if available, or using non-gas-fired facilities for fuel diversity to meet the energy and reserve needs of the electric system. As the mix of resources trends toward more renewable energy, primarily with variable and intermittent supplies of fuel (e.g. sunshine, wind, and water), maintaining a balanced power system will require a more flexible approach to energy and capacity adequacy in order to maintain operational awareness.

  - Identification of Critical Gas System Components and Dual-fuel Supplier Components
    - It is essential gas and electric operating entities coordinate to ensure that critical natural gas pipelines, compressor stations, LNG, storage, natural gas processing plants, and other critical gas system components should not be subject to electric utility load shedding in general but more specifically Under Frequency and or Manual Load shedding programs.
      - Electric transmission and distribution owners are capable of interrupting electrical load either automatically through under frequency load shedding relays installed in substations throughout North America or via manual load shedding ordered by RCs, BAs and or TOPs via SCADA. These manual and automatic load shedding protocols are part of every entity's emergency procedures. Entities should try to ensure critical gas sector infrastructure is not located on electrical circuits that are subject to the load shedding described above. Electric operators should establish contact with the gas companies operating within its jurisdiction to compile a list of critical gas and other fuel facilities which are dependent upon electric service for operations. This list should also consider the availability of backup generation at critical gas facilities. Once the list is compiled, a comprehensive review of load shedding procedures/schemas/circuits should be done to verify that critical infrastructure is not connected to or located on any of those predefined

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circuits. This review should be considered for evaluation at least annually. The best practice in this area is to try and and ensure that these facilities are not included in the initial under frequency or manual load shedding protocols at the outset.

- In a similar manner, it may be appropriate to coordinate with secondary fuel (e.g., diesel or fuel oil, onsite LNG) suppliers to ensure that any necessary critical terminals, pump stations, and other critical components are not subject to electric utility load shedding programs in general and more specifically Under Frequency and or Manual Load shedding programs. This is especially appropriate if adequate on-site fuel reserves are not guaranteed and just-in-time fuel delivery practices are required.

- Operating Reserves
  - The electric industry may want to consider adjustments to operating reserve or capacity requirements to better reflect the increased reliance on natural gas for the generation fleet. For instance, if the loss of a fuel forwarding facility has the ability to result in an instantaneous or near instantaneous electric energy loss, that contingency should be reflected in the reserve or capacity procurement for the operating day. In addition, some electric operators are considering the implementation of a risk-based operating reserve protocol that increases or decreases the amount of operating reserve procured based upon the risks identified to both the gas and electric system.

B. Preparation, Supply Rights, Training and Testing

- Assessments
  - Preparing the gas and electric system for coordinated operations benefits from up front assessments and activities to ensure that when real-time events occur, the system operators are prepared for and can effectively react. Preparation activities that may be considered include the following:
    - Developing a detailed understanding of where and how the gas infrastructure interfaces with the electric industry including:
      - Identifying each pipeline (interstate and intrastate) that operates within the electric footprint and mapping the associated electric resources that are dependent upon those pipelines.
      - Identifying the level and quantity of pipeline capacity service (firm or interruptible; primary/secondary) and any additional pipeline services (storage, no-notice, etc.) being utilized by each gas-fired generator.
      - Developing a model of and understanding the non-electric generation load that those pipelines and LDCs serve and will protect when gas curtailments are needed.
      - Identifying gas single element contingencies and how those contingencies will impact the electric infrastructure. For instance, although most gas side contingencies will not impact the electric grid instantaneously, they can be far more severe than electric side

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contingencies over time because gas side contingencies may impact several generation facilities. When identifying gas system contingencies, the electric entity should consider what the gas operator will do to secure its firm customers. This could include the potential that the gas system will invoke mutual aid agreements with other interconnected pipelines and this may involve curtailment of non-firm electrical generation from the non-impacted pipeline to aid the other.

– Understanding how gas contingencies may interact with electric contingencies during a system restoration effort.

– An additional example of appropriate actions to consider as part of the assessment phase of preparation is provided as a Natural Gas Risk Matrix[1].

- Emergency Procedure Testing and Training
  - Consider the development of testing and training activities to recognize abnormal gas system operating conditions and to support extreme gas contingencies such as loss of compressor stations, pipelines, pipeline interconnections, large LNG facilities,which can result in multiple generator losses over time. Particular attention should be focused on any gas related contingency that may result in an instantaneous generation loss.
  - Consider the addition of electric and natural gas coordination and interdependencies training to educate and exercise RCs, BAs, TOPs, and GOPs during potentially adverse natural gas supply disruptions.
  - If voltage reduction capability exists within your area, practical testing and training should be considered as part of seasonal or annual work plans.
  - The use of manual firm load shedding may be required for beyond criteria extreme gas and or electric contingencies. Consideration should be given to practicing the use of manual load-shedding in a simulated environment. These simulations should also be used as part of recurring system operator training at a minimum. The use of tabletop exercises can be a valuable training aid, but wherever possible, consideration should be given to using an advanced training simulator that employs the same tools the operators would use to accomplish the load shedding tasks.
  - Consider conducting periodic operational drills and tabletop exercises between ISO/RTO's, local emergency management entities, and the applicable natural gas industry providers (interstate and intrastate pipelines as well as local distribution companies that serve gas generators) where possible.
  - Consider the development of and drill on internal communication protocols specific to potential natural gas interruptions.
- Generator Testing

[1] https://www.misoenergy.org/StakeholderCenter/CommitteesWorkGroupsTaskForces/ENGCTF/Pages/home.aspx

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- Consideration should be given to adopting generator testing requirements for dual fuel auditing. Some items to consider when establishing a dual fuel audit program are:
  - How often should the audits be conducted and under what weather and temperature conditions.
  - Verify sufficient alternate fuel (e.g., fuel oil) inventory to ensure required generation response and output. As part of this assessment, ensure that the stored fuel is fully burnable as well since the full volume of the tank may not be pumpable at very low inventories.
  - Capacity, -ramping capability or other reductions ~~on~~ related to alternate fuels.
  - Understanding the exact time it takes to startup, switch to alternate fuel, ramp to and operate at full capacity, ramp down and resource shut down. Additional consideration should be given for those assets which require a shutdown in order to swap to an alternate fuel source.
  - The operating entity should consider any environmental constraints the generator under test must meet in order to swap to and operate on the alternate fuel.

- Capacity and Energy Assessments
  - Consideration should be given to the development of forward looking capacity analyses with which the electric industry is familiar but applying the impacts of fuel restrictions that may occur due to pipeline constraints or other fuel delivery constraints such as LNG shipments or liquid fuel delivery considerations. In order to conduct these types of assessments, the analysis needs to consider the LDC loads within the region. The weather component of the assessment should consider normal, ~~abnormal~~ and extreme conditions (i.e., Gas Design Day, which is the equivalent to the highest peak that the pipeline was designed for). This capacity assessment can be on several time horizons including; Real-time, Day Ahead, Month Ahead and Years into the future. These assessments should consider pipeline maintenance, known future outages, construction and expansion activities as well as all electric and gas industry considerations, ~~including~~ such as ~~known or~~ potential or anticipated regulatory changes~~, which are normally analyzed~~.
  - In addition to a capacity assessment that represents only a single point in time, consideration should be given to the development of a seasonal, annual or multiannual energy analysis that uses fuel delivery capability/limitations as a component. Such assessments can be scenario based, simulate varied weather conditions over the course of months, seasons and/or years, and consider the same elements as discussed in the capacity analysis. The output of the assessments should determine whether there is the potential for unserved energy and/or determine the ability to provide reserves over the period in question.

- Seasonal~~Winter~~ Readiness Reviews
  - ~~Recent system~~Winter events, such as the 2014 Polar Vortex, have magnified the need to ensure that seasonal awareness and readiness training is completed within the electric industry including System Operators, Generator Operators and Transmission Operators.

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Seasonal readiness training for winter weather could include reviews and training associated with dual fuel testing, emergency capacity and energy plans, weather forecasts over the seasonal period, fuel survey protocols and fuel storage readiness. Other areas that require attention in winter readiness reviews include reviewing and setting specific operational expectations on communications protocols. Finally, any winter readiness seminars should include individual generator readiness such as ensuring adequate fuel arrangements are in place for unit availability, adequate freeze protection guidelines are in place, understanding access to primary and secondary fuels and testing to switch to alternate fuels, ensuring all environmental permitting is in place for the fuel options available to the asset, and making sure that the Balancing and Transmission Operators are kept apprised of the unit availability. Many of the same benefits as winter readiness exercises can be realized with the added benefit of exercises under summer operating conditions when electric loads are higher than winter loads.

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- Extreme ~~Weather~~ Event Readiness Reviews
  - Seasonal readiness reviews for extreme ~~summer weather~~ events (e.g., ~~Gulf of Mexico~~ hurricane, earthquakes, wildfires) could include response to potential natural gas supply limitations and corresponding decreases in natural gas deliveries that may impact electric generation. ~~Many of the same benefits as winter readiness exercises can be realized with the added benefit of exercises under summer operating conditions when electric loads are higher than winter loads.~~

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C. Establish and Maintain Open Communication Channels

- Industry Coordination
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- Emergency Notifications to Stakeholders

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- Operating Entities may want to consider proactive notifications to stakeholders of abnormal and or emergency conditions on gas infrastructure to ensure widespread situational awareness and obligations associated with dispatch relationships in the electric sector. An example of a notification used for generators in New England appears below:

1. Notices Indicating Abnormal and/or Emergency Conditions on the Pipeline Infrastructure Serving Generators

NOTE

Notices indicating abnormal and/or emergency conditions on the pipeline infrastructure serving a Generator in the ISO RCA/BAA could come in the form of, but **not** limited to, Operational Flow Orders, Imbalance Warnings or even a verbal notification.

A) When electronic and or verbal notices indicating abnormal and or emergency conditions on the pipeline infrastructure serving a Generator in the ISO RCA/BAA are received, the Forecaster notifies the Operations Forecast and Scheduling Supervisor (or designee)

(1) The Forecaster reviews this information and depending upon the severity of the condition may pass the publicly available information along by drafting an email and submitting it to Customer Service for dissemination to each applicable Generator Designated Entity (DE) management contact(s) and/or Lead Market Participant (MP) contact(s).

NOTE

The following guideline or one tailored to the current situation can be used as a template for drafting this notification;

"ISO-NE has received the following information via the publicly available notices published by the gas pipelines:

(Insert Notice, such as Operational Flow Order or Force Majeure, etc.)

"Because of this situation, it is critical that each applicable Generator DE or Lead MP provide ISO-NE with up to date and reliable estimates of each Generator current and future capabilities including the ability to have fuel for a Generator under their control. This includes immediately reporting any information that may prevent a Generator from operating in accordance with submitted offer data, including, but **not** limited the following:

- Planned, Maintenance and or Forced outages of the Generator facilities as soon as that information is available
- Immediate reporting of any updates to outages including overruns and or early returns to service of the Generator facilities
- Any high risk activities at a Generator location that may reduce its capability or place the capability at risk
- Any fuel reductions or outages that may limit a Generator's ability to perform in any way
- Any changes to any operating limits of a Generator which must reflect the most accurate and up to date information available
- Any changes at all in a Generator ability to follow dispatch instructions including manual response rates, ability to provide reserve, ability to provide energy, and/or ability to provide capacity
- Any changes in projected Generator self schedules

Depending upon the level of severity and risk exposure, these written notifications and a means to communicate them may need to be followed up with direct verbal communications.

- Emergency Communication Protocols in the Public and Regulatory Community
  - Most every electric operating entity has long standing capacity and energy emergency plans in place that focus on public awareness, ~~abnormal~~ and emergency communications as well as appeals for conservation and load management. However, as the gas and electric industry become further dependent, considerations should be made for both industries to coordinate for extreme circumstances. Gas and electric operators in coordination with public officials, including relevant regulatory communities, may find situations where the energy of both the gas and electric sector is required to be reduced in order to preserve the reliability of both. While these types of efforts are still in their infancy they should be explored depending upon the particular circumstances of each entity's region.

D. ~~Intelligence~~ Gathering, Sharing Information, and Situational Awareness

- Fuel Surveys and Energy Emergency Protocols
  - Energy emergency procedures and fuel surveys ~~can be~~are important tools in understanding the energy situation in a region. The surveys can be used to determine energy adequacy for the region's electric power needs and for the communications and associated actions in

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anticipation or declaration of an energy emergency[2]. ~~Interestingly, ~~T~~t~~he fuel surveys[3][4] ~~will most likely~~should focus on the ~~fuel~~ availability of other types of fuels if the gas infrastructure is the constrained resource.

- Fuel Procurement
  - Operating entities should consider evaluating each electric generator's natural gas procurement and commitment to determine fuel security for the operating day.
    - The electric operating entity can collect publicly available interstate pipeline bulletin board data and compare the gas ~~procurement nominations~~schedules for individual generators against the expected electric operations of the same facility in the current or next day's operating plan. An example of this type of data collection appears below with the data helping to determine if enough fuel is available to meet an individual plant or in aggregate an entire gas fleet's expected operation for the current or future day. The report can indicate whether a fuel surplus or deficit exists by asset or for an entire pipeline. If sufficient gas has not been nominated and scheduled to the generator meter, assessments can be done to determine the impact on system operations and the operating staff may call the generator to inquire as to whether the intention is to secure the requisite gas supply to match its expected dispatch plus operating reserve designations.

[2] Energy emergency example: https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op21/op21_rto_final.pdf
[3] Seasonal survey example – See section 7.3.5 in Manual 14 http://www.pjm.com/~/media/documents/manuals/m14d.ashx
[4] Real-time survey example – See section 6.4 of Manual 13http://www.pjm.com/~/media/documents/manuals/m13.ashx

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Plant	MWh Burned So Far	MWh Before Midnight	MWh After Midnight	MWh Scheduled	MWh Surplus	Gas Scheduled
1	2201	169	1932	4493	191	34600
2	777	0	663	0	(1440)	0
3	1910	0	901	2849	38	20700
4	2131	0	0	2736	605	20028
5	5903	403	0	7706	1400	53800
6	2369	0	798	3097	(70)	22500
7	1253	0	350	93	(1510)	1000
8	2402	185	1850	5129	692	45500
9	0	0	0	28	28	300
10	3	0	525	0	(528)	0
11	0	0	0	0	0	0
12	1	0	0	0	(1)	0
13	4	0	0	0	(4)	0
14	5077	389	2864	9591	1261	65621
15	3394	215	0	3347	(262)	25048
16	3554	550	6017	221	(9900)	1500
17	10639	797	4157	17418	1825	126540
18	7249	545	3892	11096	(590)	80813
19	972	45	1066	9	(2074)	100
20	0	0	0	0	0	0
21	0	0	0	0	0	0
22	6294	0	2476	1643	(7127)	17471
23	2758	0	1209	3944	(23)	30000
24	2400	250	1250	579	(3321)	5000
25	4998	0	2317	6917	(398)	52595
26	3208	250	1189	0	(4647)	0
27	2434	0	0	2747	313	23512
28	4222	0	0	5634	1412	42963
29	2121	0	0	2343	222	20000
30	0	0	0	0	0	0
31	1141	86	860	2344	257	27000
32	0	0	0	0	0	0
33	1071	0	3490	5037	476	38325

Varying configurations of generator gas supplies can quickly complicate reports. Efforts should be made prior to the development of such reporting tools to ensure that all facets of gas scheduling can be displayed. Not all scheduled gas data will be publically available, especially when dealing with LDC~~-~~ and intrastate-connected generators. Generators are ~~often~~ occasionally supplied by multiple interstate pipelines simultaneously and may change supply sources based on daily natural gas prices. If possible, the electric operating entity should list its range of contractual arrangements with the natural gas sector such as firm capacity and supply, no-notice storage, etc.

- Gas System Visualization
  - Several Reliability Coordinators have developed visualization tools to provide scheduling and real-time operations staff with situational awareness that ties the gas and electric infrastructure together at their common point of operation. What follows is an example of one such tool that has been made generic for the purposes of the illustration. The bubbles in the tool indicate the functionality available to the user with notes that follow.

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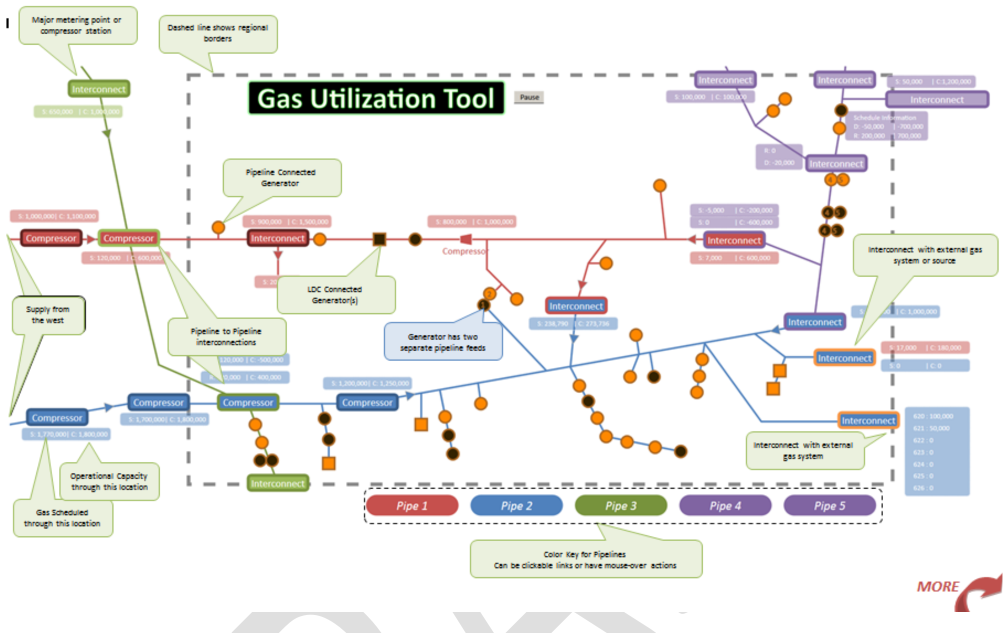

Notes:

- The display is updated automatically or on demand. Historical data is available for 30 days in the past. Can be expanded to more days or specific days.
- Generators are clickable and additional information is provided via popup message.
- Pipeline Color Key is clickable and navigates to the specific pipeline EBB.
- All of the values are in MMBtu for the gas day. When operational capacity changes, the display automatically updates based on EBB posted capacity and schedule values.
- Schedules are for the GAS DAY, rolling over at 10:00. (e.g. Gas Day 4/15/2016 starts at 10 am on 4/15 and ends at 4/16 at 10am.)
- These are SCHEDULES and may not reflect the physical flow of gas. Schedules may not match due to differences in scheduling cycles or accounting methods used by different companies.
- Just because there's room for gas to flow at a throughput meter or cross connect, doesn't mean there's gas there to move through.
- *Delivery* is gas leaving the pipeline. *Receipt* is gas entering the pipeline.
- Schedule Badges show Delivery and Receipt where there can be bi-directional scheduling and Schedule where there is not bi-directional scheduling. Most of the schedule badges show a Capacity value as well.
  - You have to net multiple schedules to derive an estimated final schedule at a location
- Some generators have a single meter to their facility with shared ownership. Through that meter, gas can be scheduled via Pipe 4 or Pipe 5.
- Many generators have multiple connections to separate pipelines and that can be displayed as well
- Meters with zero gas scheduled have darkened icons on this display

Possibilities:

- Real-time power information for the generators as well as how much gas has been consumed and how much remains
- OFO display information based on EBB postings
- Graphical trending of any value you can select

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E. Summary

The transformation in the mix of fuel sources used to power electric generation throughout North America and in particular, the increased penetration of renewable resources, as well as the continued increase in the use of natural gas ~~has naturally led~~highlights the continued need for~~ to~~ the coordination processes discussed in this~~e preceding~~ guideline. This~~e~~ guideline should serve as a reference document that NERC functional entities may use as needed to improve and ensure BES reliability and is based upon actual lessons learned over the last several years as natural gas has developed into the fuel of choice due to its availability and economic competitiveness. The document focuses on the areas of preparation, coordination, communication, and intelligence that may be applied to improve gas and electric coordinated operations and minimize interdependent risks. Each entity should assess the risks associated with this transformation and apply a set of appropriate processes and practices across its system to mitigate those risks. The guidance is not a "one size fits all" set of measures but rather a list of principles and strategies that can be applied according to the circumstances encountered in a particular system, Balancing Authority, generator fleet or even an individual Generator Operator.

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Reliability Guideline: Model Verification of Aggregate DER Models Used in Planning Studies

Action

Accept posting for 45-day public comment period.

Background

With the rapid growth of distributed energy resources (DERs) across many areas of North America, and new power flow and dynamic modeling practices being developed to accommodate these resources into the planning process,[1] focus turns to ensuring that the models used to represent aggregations of DERs are verified to some degree. DER models used in BPS planning assessments are used to represent either large utility-scale DERs (U-DERs) individually or aggregate amounts of many retail-scale DERs (R-DERs).[2] Verification of these models, at a high level, entails developing confidence that the models reasonably represent the general behavior of the installed equipment in the field (in aggregate). Since DER models used in planning studies often represent an aggregate behavior of hundreds or even thousands of individual devices, guidance is needed for Transmission Planners (TPs) and Planning Coordinators (PCs) to effectively perform an appropriate level of model verification to ensure that transmission planning assessments are capturing the key impacts that aggregate amounts of DERs can have on BPS reliability.

This guideline provides TPs and PCs with tools and techniques can be adapted for their specific systems to verify that the aggregate DER models created are a suitable representation of these resources in planning assessments. The first step in DER model verification is collecting data and information regarding actual DER performance (through measurements) to BPS disturbances or other operating conditions. Measurements of DERs (individual or aggregate) are currently sparse, and this guideline recommends practices for ensuring adequate data are collected for larger utility-scale DERs as well as capturing the general behavior of aggregated retail-scale distributed resources. This guideline discusses when model verification is triggered, as well as how to understand the mix of different DER characteristics. This guideline describes differences between verifying the model response for aggregate R-DERs and larger U-DERs. Describing the recommended DER model verification practices can also help TPs, PCs, and Distribution Providers (DPs) understand the types of data needed for analyzing DER performance for these purposes both now and into the future as DER penetrations continue to rise. As has been observed in past large-scale disturbances, the response of DERs to BPS disturbances can significantly impact overall reliability of the BPS.[3]

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[1] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf

[2] In the modeling guidance developed by NERC SPIDERWG, these types of DERs are referred to as utility-scale DERs (U-DERs) and retail-scale DERs (R-DERs) for the purposes of modeling.

[3] https://www.ofgem.gov.uk/publications-and-updates/ofgem-has-published-national-grid-electricity-system-operator-s-technical-report

Summary

SPIDERWG asks the RSTC to authorize this *Reliability Guideline: Model Verification of Aggregate DER Models used in Planning Studies* for a 45-day industry commenting period as per the approval process for Reliability Guidelines.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Guideline

Model Verification of Aggregate DER Models used in Planning Studies

September 2020

RELIABILITY | ACCOUNTABILITY




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Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

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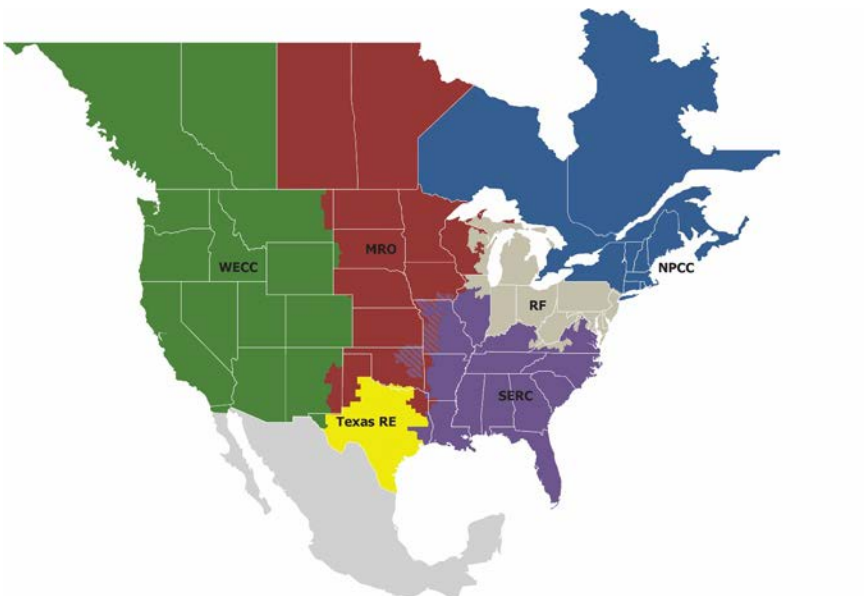
Preface

*Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. T*he 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

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Preface

The NERC Reliability and Security Technical Committee (RSTC), through its subcommittees and working groups, develops and triennially reviews reliability guidelines in accordance with the procedures set forth in the RSTC Charter. Reliability guidelines include the collective experience, expertise, and judgment of the industry on matters that impact bulk power system (BPS) operations, planning, and security. Reliability guidelines provide key practices, guidance, and information on specific issues critical to promote and maintain a highly reliable and secure BPS.

Each entity registered in the NERC compliance registry is responsible and accountable for maintaining reliability and compliance with applicable mandatory Reliability Standards. Reliability guidelines are not binding norms or parameters; however, NERC encourages entities to review, validate, adjust, and/or develop a program with the practices set forth in this guideline. Entities should review this guideline in detail and in conjunction with evaluations of their internal processes and procedures; these reviews could highlight that appropriate changes are needed, and these changes should be done with consideration of system design, configuration, and business practices.

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Executive Summary

With the rapid growth of distributed energy resources (DERs) across many areas of North America, and new power flow and dynamic modeling practices being developed to accommodate these resources into the planning process,[1] focus turns to ensuring that the models used to represent ~~aggregate amounts~~aggregations of DERs are verified to some degree. DER models used in BPS planning assessments are used to represent either large utility-scale DERs (U-DERs) individually or aggregate amounts of many retail-scale DERs (R-DERs).[2] Verification of these models, at a high level, entails developing confidence that the models reasonably represent the general behavior of the installed equipment in the field (in aggregate). Since DER models used in planning studies often represent an aggregate behavior of hundreds or even thousands of individual devices, guidance is needed for Transmission Planners (TPs) and Planning Coordinators (PCs) to effectively perform an appropriate level of model verification to ensure that transmission planning assessments are capturing the key impacts that aggregate amounts of DERs can have on BPS reliability.

Commented [JN1]: Is it assumed that U-DERs are connected to the BPS and R-DERs are connected to the distribution system? If so, we may want to clarify this. A clear definition of each type would be helpful. What is the delineation between the two types? Is it a size (i.e. 1 MW) or percentage of load on a circuit or transmission connected transformer?

Commented [JS2R1]: The SPIDERWG Coordination group has defined the U-DER and R-DER term in the definitions document for more specificity. However, both U-DER and R-DER are connected to the Distribution system. U-DER is modeled at the distribution bus and R-DER is modeled across an impedance connected to the distribution bus.

Added link to SPIDERWG terms and definitions.

This guideline provides TPs and PCs with tools and techniques can be adapted for their specific systems to verify that the aggregate DER models created are a suitable representation of these resources in planning assessments. The first step in DER model verification is collecting data and information regarding actual DER performance (through measurements) to BPS disturbances or other operating conditions. Measurements of DERs (individual or aggregate) are currently sparse, and this guideline recommends practices for ensuring adequate ~~amounts of~~ data are collected for larger utility-scale DERs as well as capturing the general behavior of ~~aggregate amounts of~~aggregated retail-scale distributed resources. This guideline discusses when model verification is triggered, as well as how to understand the mix of different DER characteristics. This guideline describes differences between verifying the model response for aggregate R-DERs and larger U-DERs. Describing the recommended DER model verification practices can also help TPs, PCs, and Distribution Providers (DPs) understand the types of data needed for analyzing DER performance for these purposes both now and into the future as DER penetrations continue to rise. As has been observed in past large-scale disturbances, the response of DERs to BPS disturbances can significantly impact overall reliability of the BPS.[3]

Key Findings

During the development of this guideline, the NERC System Planning Impacts from DERs Working Group (SPIDERWG) identified the following key findings:

- **Visibility and Measurement:** Verification of DER models requires measurement data to capture the general behavior of these resources. For R-DERs, data is most useful from the ~~distribution~~high-side of the transmission-distribution (T-D) interface, most commonly ~~at~~ the T-D transformers. For U-DERs, this may be at the point of interconnection of each ~~larger~~ U-DER.

Commented [JN3]: How would load masking be accounted for if the measurement is taken at the T-D transformer? In most instances, the amount of DER is less than the load consumed and only reduces net load at the distribution circuit or substation.

Is it expected to measure each DER individually and aggregate the distributed generation total at the transformer?

Commented [JS4R3]: In the document, we call out specific monitoring for larger U-DER installations based on group discussion as they have a larger impact at the modeled distribution bus. Looking at Appendix B, the load is also modeled in aggregate at that bus, so the load would be accounted for in the playback to verify the set of models.

- **Aggregation of U-DER and R-DER Behavior:** Verification of aggregate DER models becomes more complex when both U-DER and R-DER are modeled on the distribution system with different performance capabilities and operational settings, and verification practices will need to adapt to each specific scenario.
- **Data Requirements:** Data requirements vary between steady-state and dynamic model verification; however, both steps are critical to developing a useful aggregate DER model. DER verification practices should ensure that both steady-state and dynamic modeling are supported.
- **Event Selection:** A relatively large disturbance on the BPS (e.g., nearby fault or other event) is the most effective means of dynamic model verification; however, these events are not necessarily the only trigger of

[1] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf

[2] In the modeling guidance developed by NERC SPIDERWG, these types of DERs are referred to as utility-scale DERs (U-DERs) and retail-scale DERs (R-DERs) for the purposes of modeling.

[3] https://www.ofgem.gov.uk/publications-and-updates/ofgem-has-published-national-grid-electricity-system-operator-s-technical-report

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model verification. It should be noted that aggregate model verification is not a one--time exercise. Since system loads and DER output levels keep changing, as and when more events happen and the measurement data becomes available the verified models should be checked to ensure that they indeed can replicate the other events that have happened in the system.

- **Concept of Verified Models:** ~~Creating~~ Developing an aggregate DER model is not equivalent to having a verified model[4]. ~~This is true for all sets of models, and is not exclusive to aggregate DER models.~~ ~~A~~A verified model ~~is not always~~should not be expected to be ~~equivalent~~ usable ~~to a model useful~~ for all ~~a specific~~ types of planning studi~~y~~ies. A developed aggregate DER model for the positive sequence simulation tools ~~is one that is proposed to represent~~is ~~the expected equipment~~a mathematical representation at a given location. Whereas, ~~V~~verification of th~~is~~ise ~~simulation~~ model is an exercise that entails comparing the ~~proposed~~ model performance to the actual equipment performance during staged or grid events and tuning relevant parameters to match the model behavior with actual field response. ~~Creating~~ Developing a model useful for study, based on information attained through model verification, requires engineering judgement.[5]

Recommendations

From the key findings listed above, the following recommendations are intended to help guide TPs and PCs in performing DER model verification:

- TPs and PCs should ~~E~~encourage DPs and other applicable entities that may govern DER interconnection requirements to revise interconnection requirements to ensure both ~~high-speed and low-speed~~high and low time-resolution data collection. ~~The expected data, as outlined in this guideline, is not necessarily as detailed as any recommended data collection requirements for BPS-connected resources.~~The expected data, as outlined in this guidance, is not necessarily more refined than any recommended data required for BPS-connected resources.
- TPs, PCs, TOs, and other applicable entities that may govern DER interconnection requirements should coordinate with DPs to determine the necessary measurement information that would be of use for the purposes of DER modeling and model verification, and jointly develop requirements or practices that will ensure this data is available.
    - This collaboration should include a minimum set of necessary data for performing model verification.
    - This collaboration should include a procedure where other models, rather than current models, can be verified with additional data should a more accurate representation be required.
- TPs and PCs should coordinate with their TOs, TOPs, and DPs to gather measurement data to verify the general behavior of aggregate DER[6]. Relevant T-D interfaces should be reviewed using data from the supervisory control and data acquisition (SCADA) system or other available data points and locations.

[4] This is true for all sets of models, and is not exclusive to aggregate DER models.

[5] A verified model may not be enough for a particular study as study conditions may be different than verified conditions (e.g., future years, different time of day).

[6] SPIDERWG is actively developing guidance on how this coordination should take place to ensure reliability of the BPS.

Commented [JN5]: May want to add a bullet here that mentions that the verified model would be used to extrapolate and determine expected performance of a future state where additional DER is added to the system.

Commented [JS6R5]: SPIDERWG Verification team does not necessarily agree with the idea that a verified model is the same as one useful for future studies. These verified models CAN be used, but require engineering judgement based on the study conditions for any changes to meet the study's scope. For instance, a verified model at 1 PM does not have the same available power for a Solar PV DER as the available power at 10 AM for some installations.

Commented [PM7]: Should this be high resolution and low resolution instead of speed

Commented [JS8R7]: Yes, this should be resolution versus speed.

Commented [MJ9]: I don't know what this means specifically and what action is needed both from the PC and then the DP once they receive this sort of "Encouragement". Please make this into something that is actionable by both parties.

Commented [JS10R9]: Added a phrase to specify what "encouragement" we are asking for as well as who does the "encouragement"

Commented [JN11]: Does this guideline not cover BPS connected resources? If so , it needs to me made more clear that this guideline is specific to non-BPS DER.

Commented [JS12R11]: Yes, this guideline is focused on DER, which by SPIDERWG definitions does not include BPS connected devices.

Commented [MJ13]: There is some coordination that does happen in an effort to collect data for what is assumed to be aggregate R-DER (rooftop solar and small solar and storage facilities). What additional coordination is expected here as the reality is that not everything will be accounted for? Can we be more granular regarding the "coordination" to some extent. What additional coordination is specifically needed?

Commented [JS14R13]: Added "measurement" to specify the amount of data. From discussions in SPIDERWG, the only coordination so far is nameplate capacity and similar set points. We are asking for coordination of high and low resolution measurement data in order to verify the planning models. Additionally, this recommendation attempts to point to the Coordination subgroups major Reliability Guideline.

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Introduction

Many areas across the BPS in North America are experiencing an increase in the penetration of DERs, and TPs and PCs are adapting their long-term transmission planning practices to accommodate these relatively new resources into their reliability studies. Aggregate amounts of DERs should be modeled and reflected up to the BPS level when performing these studies. BPS fault events in 2018[7] highlighted the growth of DERs in California and the potential impact these resources can have on BPS performance during grid disturbances. Rapidly growing penetrations of DERs across North America have sparked the need for modeling the aggregate behavior of DERs, and in some instances the individual behavior of larger U-DERs, to a suitable degree to incorporate into BPS planning studies, much like how TPs and PCs currently account for aggregated load. SPIDERWG has provided recommended practices for DER modeling.[8,9] These guidance materials provide TPs and PCs with recommendations for modeling aggregate amounts of DERs. However, some degree of uncertainty is involved when applying assumptions or engineering judgement in the development of the model. Therefore, this guideline tackles the need for verification practices after aggregate DER models are developed to ensure that the models used to represent DERs are in fact representative of the actual or expected behavior. Verification of models is paramount to obtaining reasonable and representative study results. The goal is for TPs and PCs to gain more confidence in their aggregate DER models and utilize them for BPS planning studies.

There will inherently be lag between the time in which steady-state and dynamic models for DERs are created and when verification of these models using actual system disturbances and engineering judgement can take place. However, this should not preclude the use of these models in BPS reliability studies. Engineering judgment can be used in the interim to develop reasonable and representative DER models that capture the key functional behaviors of DERs. Explicit modeling of aggregate amounts of DERs is strongly recommended,[10] versus netting these resources with load, as the key functional behaviors are different.

Difference between Event Analysis and Model Verification

While some of the same data may be used between event analysis and model verification, especially dynamic model verification, the two procedures are not necessarily the same. Event analysis seeks to comprehensively understand the disturbance and to identify the root cause of the event. The data needed to execute event analysis typically includes as a vast array of event logs, dynamic disturbance recordings, pre-contingency operating conditions, and other forms of documentation. The pre-contingency operating condition and the dynamic disturbance recordings captured during these events can be used for steady-state and dynamic model verification. This document is intended to help TPs and PCs ensure DER model fidelity using data from actual system disturbances. Model verification's purpose is to add fidelity to models. While some recorders can be used in the same process as event analysis, the processes are quite different.

Recommended DER Modeling Framework

SPIDERWG recently published NERC *Reliability Guideline: Parameterization of the DER_A Model*, which describes recommended dynamic modeling practices for aggregate amounts of DERs. That guideline also builds on previous efforts within SPIDERWG and the NERC Load Modeling Task Force (LMTF) laying out a framework for recommended DER modeling in BPS planning studies. DER models are typically representative of either one or more larger U-DERs

Commented [PSJ15]: Placing this sub-section before the DER modeling framework sub-section may improve the readability.

Commented [JS16R15]: Swapped based on recommendation.

Commented [PSJ17]: In my opinion this sub-section should be towards the end of the Introduction section.

Commented [JS18R17]: Kept here as flow is DER model framework into process of verification.

[7] https://www.nerc.com/pa/rrm/ea/April_May_2018_Fault_Induced_Solar_PV_Resource_Int/April_May_2018_Solar_PV_Disturbance_Report.pdf
[8] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf
[9] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_Data_Collection_for_Modeling.pdf
[10] https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf

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or aggregate amounts of smaller R-DERs spread across a distribution feeder[11]. The steady-state model for these resources is placed at a single modeled distribution bus, with the T-D transformer modeled explicitly in most cases. The modeling framework is reproduced in Figure I.1. This guideline uses modeling concepts consistent with the recommended modeling framework previously published and used by industry on recommended DER model verification practices. Please refer to the aforementioned guidelines for more information.

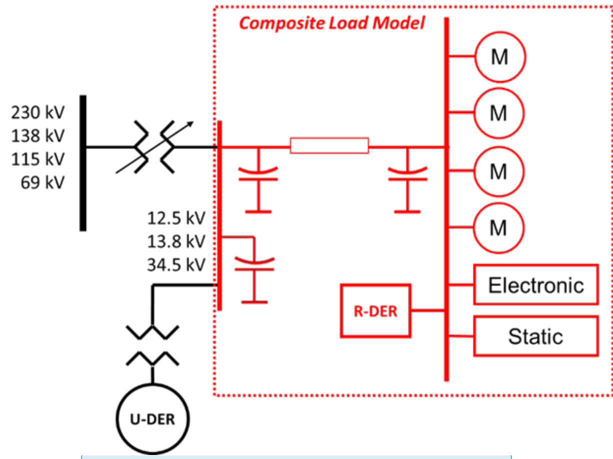

Figure I.1: DER_A Modeling Framework

~~Difference between Event Analysis and Model Verification~~

~~While some of the same data may be used between event analysis and model verification, especially dynamic model verification, the two procedures are not necessarily the same. Event analysis seeks to comprehensively understand the disturbance and to identify the root cause of the event. The data needed to execute event analysis typically includes as a vast array of event logs, dynamic disturbance recordings, pre-contingency operating conditions, and other forms of documentation. The pre-contingency operating condition and the dynamic disturbance recordings captured during these events can be used for steady-state and dynamic model verification. This document is intended to help TPs and PCs ensure DER model fidelity using data from actual system disturbances. Model verification's purpose is to add fidelity to models. While some recorders can be used in the same process as event analysis, the processes are quite different.~~

Guide to Model Verification

Model verification first requires an adequate model be developed, and then for an entity to gather data to match the model performance with that information. Model verification of the models used in planning studies occurs when ~~utilizing~~ TPs and PCs utilize supplemental information to verify ~~against~~ parameters in ~~the~~their transmission model used ~~by TPs and PCs~~ in their high fidelity studies. The process begins with a perturbation on the system resulting in a visible performance characteristic from devices. Such data is stored and sent[12] to the TP/PC for use in validating their set of representative models of those devices. The process continues with the PC perturbing their model and storing

[11] References to U-DER and R-DER here are model related discussions. This designation should be only be used with respect to transferring the measurements taken from the DER into its model representation.

[12] Generally, this is done by Reliability Coordinators (RCs), Transmission Operators (TOPs), and Transmission Owners (TOs); however, this can also be done by DPs in reference to monitoring equipment on their system

Commented [MJ19]:

Commented [JS20R19]: Unsure on change recommended, no change made.

Commented [JS21]: Levetra/Pubs, this is getting cut off, please help.

Commented [PSJ22]: It may be better to give the DER_A model diagram here.

Commented [JS23R22]: I agree that clarity always helps for assisting the guideline points; however, the linked DER_A Parameterization guide already has those sections detailed out and we point to those products rather than reproduce what is in them.

Commented [PSJ24]: Placing this sub-section before the DER modeling framework sub-section may improve the readability.

Commented [JS25R24]: Swapped based on recommendation.

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the outputs[13]. Those model outputs and the measured outputs are compared and if a sufficient match based on the TP/PC procedures, the verification procedure stops. If not, small tuning adjustments are made to verify the set of models as it relates to the measured data. It is anticipated that verification of planning models incorporating aggregate DER take more than one of these perturbations. An example of model verification can be found in Appendix B, which details an example using the playback models to verify a set of DER models.

Three Phase versus Positive Sequence Model Verification

The majority of planning studies performed by TPs and PCs use RMS[14] fundamental frequency, positive sequence simulation tools.[15] Hence, steady-state powerflow and dynamic simulations assume[16] a balanced three-phase network, which has conventionally been a reasonable assumption for BPS planning (particularly for steady-state analysis). Therefore, this guideline focuses on verification of the models used for these types of simulations. However, other simulation methods may be used by TPs and PCs, based on localized reliability issues or other planning considerations. These studies, using more advanced or detailed simulation models, may require more detailed three-phase ~~modeling~~ simulation methods~~tools~~ such as three-phase RMS dynamic simulation, electromagnetic transient (EMT~~)~~), or co-simulation ~~tools~~. Those ~~tools~~ methods require more detailed modeling data and verification activities. However, DER model verification using those ~~tools~~ methods is outside the scope of this guideline as the majority of the planning studies are based on the RMS fundamental frequency and positive sequence quantities.

Data Collection for Model Verification of DERs

Key Takeaway:
The process of model verification requires two key aspects: a suitable model to be verified and measurement or other data that can be compared against model performance.

The process of model verification requires two key aspects: a suitable model to be verified and measurement or other data that can be compared against model performance. This guideline will cover the necessary data points for performing model verifications for developing an aggregate DER model. However, varying degrees of model verification can be performed for different levels of data available. While having all the necessary data available for model verification would be preferable, it is understood that this data may not be available and that monitoring capability may be limited in many areas today. Measurement data is a critical aspect of understanding the nature of DER and its impact on the BPS. Applicable entities that may govern DER interconnection requirements are encouraged to develop interconnection requirements for large-scale DERs that will enable data to be available for the purposes of developing accurate DER models moving forward. Further, monitoring equipment at the T-D interface would make available data to capture the aggregate behavior of DERs, which can support both DER model verification and load model verification.

Considerations for Distributed Energy Storage

Recent discussions regarding the expected growth of energy storage, particularly battery energy storage systems (BESSs), relate to both BPS-connected and distribution-connected resources. This guideline focuses ~~solely~~ on the distributed BESSs where energy storage is concerned. Other documents coming from the NERC IRPTF are dealing with BPS-connected devices and their impact, which includes BPS-connected BESSs. Many of the recommendations regarding data collection and model verification of aggregate DERs ~~can~~ also ~~apply~~applies for distribution-connected ~~BESSs~~BESSs~~, and this~~. This guideline covers this in more detail throughout where distinctions on distribution-connected BESS can be more informative. ~~between BESS and other types of DER can be informative.~~

[13] Practices may change related to the software changes, which is similar to the current load model verification practices. SPIDERWG is reviewing and recommending simulation practice changes regarding to DER in other work products.
[14] Root-mean-square
[15] This is different from three-phase simulation tools used by DPs to capture things like phase imbalance, harmonics, or other unbalanced effects on the distribution system.
[16] This assumption is inherently built into the power flow and dynamic solutions used by the simulation tools.

Commented [PSJ26]: It may be better to rename this as "Scope of Guideline"

Commented [JS27R26]: Title of heading not changed as other titles do not clarify the discussion of the section as well as this one.

Commented [RD28]: Should probably first include three phase RMS dynamic simulations like in OpenDSS and/or GridLab-D…co-simulation and EMT can then follow

Commented [JS29R28]: Added text in the sentence.

Commented [MP30]: Aggregated models may not require EMT type modeling because that are approximate models by definitions. EMT should be reserved for individual equipment modeling where it makes far more sense. E.g. we do not require EMT model of aggregated DER.

Commented [JS31R30]: Agreed, added a sentence to return back to pos sequence and ensure this guideline provides guidance on those.

Commented [PSJ32]: In my opinion this sentence is a very key information and should be included in the Guide to Model verification section.

Commented [JS33R32]: Added some language in the above section that mimics the idea, but isn't a direct copy.

Commented [MJ34]: From our experience, this is actually happening today. Some TSPs are actually requiring PMUs to be installed for DERs being interconnected at 75 – 100 MW or above. Is the group thinking about requiring something above and beyond this for monitoring devices?

Commented [JS35R34]: In the monitoring devices chapter, we discuss the types of recording devices. We are not requiring more than what is similarly seen at the BPS connected devices, except with the monitored location at high side of the T-D interface, or at the POI of U-DERs where capable. We are encouraging entities here to allow for monitoring devices to be placed on the distribution system.

Commented [JN36]: Why would you not include BPS connected energy storage as well? Doesn't the guideline cover BPS connected U-DERs? If it doesn't, it may need to be made more clear in the introduction that this guideline is only for DERs not connected to the BPS.

If BPS connected DER is covered by another guideline, it may be good to call that out here.

Commented [JS37R36]: This guideline does not cover BPS connected devices as the DER definition comments above. Added a sentence to reference the IRPTF conversations regarding BPS connected devices.

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Chapter 1: Data Collection for DER Model Verification

The data and information needed to create a steady-state and dynamic model for individual or aggregate DERs is different that the data and information used to verify those models. TPs and PCs should work with their DPs to collect information pertaining to existing DERs, and also work with the DP and other applicable entities to forecast future levels of DERs for planning studies of expected future operating conditions. The NERC *Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies*[17] describes the types of data and information necessary to create a suitable steady-state and dynamic model for DERs used for planning studies. On the other hand, data used for DER model verification focuses more on the actual performance of aggregate or individual DERs that can used to compare against model performance.

Before describing the verification process in subsequent chapters, this chapter will first describe the data and information used for verifying the DER model(s) created.

Data Collection and the Distribution Provider

Key Takeaway:
The "source" of the DER data may come from other entities than a DP, such as a DER developer. It is intended that clear coordination between DPs, TPs, and PCs highlight the needs required to collect the data from the "source".

DPs are the most suitable entity to provide data and information pertaining to DERs within their footprint since DPs conduct the interconnection studies and may have access to the measurements necessary to perform DER model verification. Applicable entities that may govern DER interconnection requirements states, upon their review of interconnection requirements for DERs connecting to the DPs footprint, are encouraged to ensure DPs are capable of collecting data for model verification purposes as unverified models have an impact on BPS studies. This impact compounds on itself as the DER penetration in a local area grows; however, access to measurements for verifying model performance alleviates those study impacts. Sometimes the actual "source" of the data is a DER developer or other distribution entity, who is not a functional NERC entity. TPs, PCs, and Transmission Owners (TOs) are encouraged to coordinate with DPs and respective DER developers, generators, owners, or other distribution entities related to DER in order to develop a mutual understanding of the types of data needed for the purposes of DER modeling and model verification. Coordination between these entities can also help develop processes and procedures for transmitting the necessary data in an effective manner. Two of the primary goals of this guideline are to help ensure that DPs, TPs, PCs, and TOs understand the types of data needed to successfully verify DER models, and to provide recommended practices for gathering this data and applying it for verification purposes. It is intended that with clear coordination on the needs for the data, the best "source" of this data will become apparent.

DER model verification starts with having suitable data available for DERs to make reasonable engineering judgments regarding how to model the aggregate behavior of DERs. There is no one-size-fits-all method to this effort; entities should coordinate with each other to develop solutions most applicable for their specific systems and situations. However, common modeling practices and similar data needs will exist, and these are discussed in this chapter in more detail.

Monitoring Requirements in IEEE 1547

The IEEE 1547 standard represents a series of standards that provide requirements, recommended practices, and guidance for addressing standardized interconnection of DER. IEEE 1547 was first published in 2003 and later updated

[17] Guideline found here (Review hyperlink upon completion)

Commented [LG38]: Considering the current MOD-032 SAR, will this language be in alignment with the standard?

Commented [JS39R38]: The MOD-032 SAR parrots the change from LSE to DP, so yes, the language is in agreement. Additionally, the MOD-032 SAR asks to change to dynamic and steady-state data for aggregate DER, which is concurrence with this language.

Commented [DK(TD-140]: DER developers build and sell DER plants. They typically do not own or operate the plants. So it is more likely to request data from DER generators/owners or utility companies.

Commented [JS41R40]: Added language to address the comment

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in 2018 to address the proliferation of DER interconnections. Both IEEE 1547-2003[18] and IEEE 1547-2018[19] standards are technology neutral. The monitoring requirements for both standards are presented here:

- **IEEE 1547-2003:** The IEEE 1547-2003 standard, applicable for DER installations installed prior to the full adoption and implementation of IEEE 1547-2018,[20] included provisions for DERs with a single unit above 250 kVA or aggregated more than 250 kVA at a single Point of Common Coupling (PCC) to have monitoring for active power, reactive power, and voltage. However, the standard did not specify any requirements for sampling rate, communications interface, duration, or any other critical elements of gathering this information. Further, DER monitoring under this requirement was typically through mutual agreement between the DER owner and the distribution system operator. Therefore, it is expected that data and information for these legacy DERs is likely very limited (at least from the DER itself). For legacy R-DERs, this may pose challenges in the future for DER model verification and BPS operations.
- **IEEE 1547-2018:** The IEEE 1547-2018 standard places a higher emphasis on monitoring requirements and states that "the DER shall be capable of providing monitoring information through a local DER communication interface at the reference point of applicability….The information shall be the latest value that has been measured within the required response time." Active power, reactive power, voltage, current, and frequency are the minimum requirement for analog measurements. The standard also specifies monitoring parameters such as maximum response time and the DER communications interface. Therefore, larger U-DER installations will have the capability to capture this information, and DPs are encouraged to establish interconnection requirements that make this data available to the DP (which will be applicable to distribution and BPS planning and operations).

Information and data can be collected for the purposes of DER model verification from locations other than at the DER PCC. This is particularly true for capturing the behavior of aggregate amounts of R-DERs. However, particularly for larger U-DER installations, this type of information can be extremely valuable for model verification purposes.

Recording Device Considerations

Key Takeaway:
Recording capabilities will vary on IEEE 1547-2003 and IEEE 1547-2018 compliant DER. It is critical to understand these capabilities when considering additional recording devices.

This section specifies considerations for applicable entities that may govern DER interconnection requirements regarding recording devices. In addition to the information that the IEEE 1547-2018 standard requires to monitor, event-driven capture of high-resolution voltage and current waveforms are useful for DER dynamic model verification. These allow the key ~~functions~~responses of fault ride-through, instability, tripping and restart to be verified. It is recommended that the built-in monitoring capabilities of smart inverter controllers or modern revenue meters are fully explored by relevant entities since they may provide similar data as a standalone monitor. These meters may also be able to monitor power quality indices.

Entities may receive nominal nameplate information for the resource but the actual output characteristics will be influenced by factors such as the resource's age and ~~ambient temperatures.~~weather ~~conditions.conditions~~conditions.~~temperatures.~~. Recording devices should be capable of collecting, archiving and managing disturbance, fault information and normal operation conditions identified by protection equipment such as relays and significant changes observed during normal operating conditions (e.g. PMU reading).

[18] https://standards.ieee.org/standard/1547-2003.html
[19] https://standards.ieee.org/standard/1547-2018.html
[20] It is expected that DERs compliant with IEEE 1547-2018 will become available around the 2021 timeframe based on the progress and approval of IEEE 1547.1: http://grouper.ieee.org/groups/scc21/1547.1/1547.1_index.html

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An example of a recording device is the Power Quality meters (PQ meters), which are a type of measurement device used in a multitude of applications including compliance, customer complaint troubleshooting, and incipient fault detection. These devices are programmable to record voltage and current waveforms during steady-state conditions as well as during system events. These types of measurement devices record both RMS and sinusoidal waveforms at many different sample rates and are IEC code compliant on their RMS and sinusoidal samplings. These types of meters are viable when capturing the aggregate performance of DER on the BPS depending on the placement of the device, and can function as a standalone meter or as part of a revenue meter. TPs and PCs should collaborate with applicable entities that may govern DER interconnection requirements ~~regarding recording devices~~ and the DP, regarding recording devices, so that these recording devices accomplish the objectives of each entity~~, as capturing this performance is not only useful to the TP~~. The improved model quality and fidelity will benefit all the stakeholders. ~~It is recommended that new DER installations have some sort of smart meter capability[21] so that explicit output levels of DER can be collected.~~

> ~~**Key Takeaway:**~~
> ~~Recording capabilities will vary on IEEE 1547-2003 and IEEE 1547-2018 compliant DER. It is critical to understand these capabilities when verifying DER models.~~

Placement of Measurement Devices

Selecting measurement locations for DER steady-state and dynamic model verification depends on whether TPs and PCs are verifying U-DER models, R-DER models, or a combination of both. The following recommendations should be considered by TPs, PCs, and DPs when selecting suitable measurements for DER model verification:

- **R-DER:** An R-DER model is an aggregate representation of many individual DERs. Therefore, the aggregate response of DERs can be used for R-DER model verification. This is suitably captured by taking measurements of steady-state active power, reactive power, and voltage at T-D interface[22]. ~~Note that such a measurement would include the combined response from the load and the R-DER.~~ This may be acquired by measurements at the distribution substation for each T-D transformer bank or along a different distribution connected location[23].
- **U-DER:** U-DER models represent a single (or group of) DER; therefore, the measurements needed to verify this dynamic model must be placed at a location where the response of the U-DER (or group of DER) can be differentiated from other DERs and load response. For U-DER connecting directly to the distribution substation (even through a dedicated feeder), the measurements for active power, reactive power, and voltage can be placed either at the facility or at the distribution substation. For verifying groups of DERs with similar performance, measurements capturing one of these facilities may be extrapolated for verification purposes (using engineering judgment). Applicable entities that may govern DER interconnection requirements should consider establishing capacity thresholds (e.g., 250 kVA in 1547-2003) in which U-DER should have monitoring equipment at their Point of Connection (PoC) to the DP's distribution system.
- **Combined R-DER and U-DER:** Situations where both U-DER and R-DER exist at the distribution system may be quite common in the future. Where possible, the response of U-DERs (based on DER modeling practices) should be separated from the response of R-DERs and end-use loads. Measurement locations at the T-D

> **Key Takeaway:**
> Measurement locations of DER performance depend on the type of DER model (U-DER vs. R-DER) being verified. Aggregate R-DER response can be captured at the T-D interface, whereas explicit model verification of U-DER models may require data at specific larger DER installations.

~~[21] Possibly something like PG&E has as seen Here~~

[22] Note that such a measurement, expectedly, could include the combined response from the load and the R-DER; however, this will not undermine the accuracy of the model verification since the model framework also includes both load and resource components as described in the DER model framework sections.

[23] While uncommon, measurement data along a distribution feeder can replace data at a T-D interface. Entities are encouraged to pursue the location that is easiest to accommodate the needs of all entities involved.

Commented [MJ42]: It's not clear what is intended here. Someone is going to have to pay for these recording devices and it's not apparent how a recording devices placed with the objective of verifying a model developed by the TP is also going to be beneficial for the DP or the DER developer.

Commented [JS43R42]: SPIDERWG understands that there is a cost associated with this equipment, but as this is a reliability guideline, we are focused on the reliability benefit of these recording devices, which benefit all stakeholders as improved model fidelity and quality allows for accurate studies.

As accurate studies feed the ability to optimize the transmission and distribution system, these allow for rates to be set that the DP/DER developer is highly interested in.

Commented [PM44]: Included this line here since the next bullet point talks about separating load and U-DER response. It is important to mention that the measurements for RDER will include load response as well and both needs to be verified together

Commented [JS45R44]: Included.

Commented [JN46]: These measurements will be affected by load downstream of the T-D interface. Is the load modeled separately from the DER or are they modeled together at this interface? If they are modeled separately, how are the two separated, unless metered at each individual DER?

Commented [JS47R46]: See Parag's clarification on the load. They are separated based on the modeling practices, currently emphasized to separate R-DER from Load in the framework; however, the measurement will account for both aggregate load and aggregate DER. The separation occurs based on metered U-DER in the next section.

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interface are recommended in all cases, and additional measurements for capturing and differentiating U-DERs may also be warranted.

As described, the type of DERs and how they are modeled will dictate the placement of measurement devices for verifying DER models. Figure 1.1 illustrates the concepts described above regarding placement of measurement locations for capturing the response of R-DERs, U-DERs, or both. In the current composite load model framework, specific feeder parameters are automatically calculated at initialization to ensure voltage at the terminal end of the composite load model stays within ANSI acceptable voltage continuous service voltage. These parameters represent the aggregated impact of individual feeders, as~~,~~ indicated by the dashed box in Figure 1.1. Each of the highlighted points in Figure 1.1 pose a different electrical connection that this guideline calls out. At a minimum, placement at the high or low side of the transformer provides enough information for both steady-state and dynamic model verification. For U-DER, it is suggested that monitoring devices are placed at their terminal as shown in Figure 1.1. ~~(indicated in Figure 1.1 at the high side connection)~~. While other locations are highlighted, they are not necessary for performing model verification when the two aforementioned locations are available; however, they may be able to replace or supplement the data and have value when performing model verification.

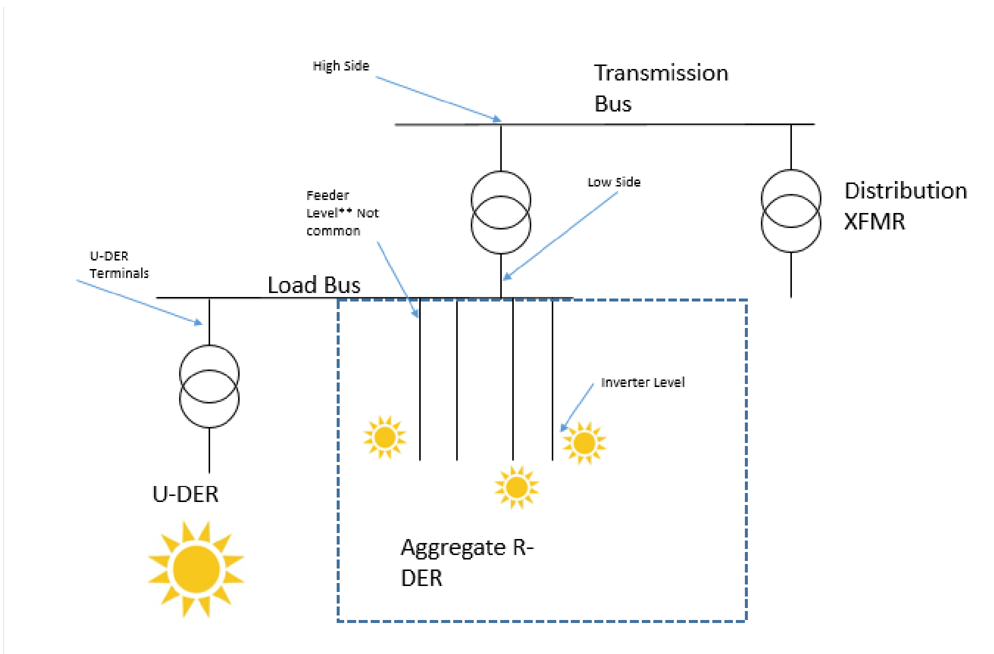

Figure 1.1: Illustration of Measurement Locations for DER Model Verification

Measurement Quantities used for DER Model Verification

~~Both U-DER and R-DER m~~Measurement devices used for ~~aggregate~~ DER steady-state model verification for both U-DER and R-DER should be capable of collecting the following data at their nominal frequency:

- Steady-state RMS voltage (Vrms)
- Steady-state RMS current (Irms)

Commented [PM48]: In the current composite model, the feeder parameters are not automatically calculated. The guidance (reflected in the default parameters) is to choose the feeder parameters such that a voltage drop of 4-6% is achieved from the feeder head to the feeder end, and the X to R ratio is 1. These feeder parameters are automatically adjusted during initialization if and only if the voltage at the terminal of the composite load components fall below 0.95 pu, which is the ANSI acceptable voltage continuous service voltage level

Commented [JS49R48]: Changes made in text

Commented [RD50]: Minor comment: the figure doesn't actually indicate the feeder parameters or the equivalent that is being calculated.

Commented [JS51R50]: Changes made in text.

Commented [LG52]: This is good for people to know so that they know they don't have verify feeder parameters all the time. I would ask the group to consider a more rural scenario when U-DER and R-DER will be mixed together on the same line to the substation. Wouldn't we want to verify the impedance of a "long" distribution line? Especially if the revenue meters are at the customer site and not the substation.

Commented [JS53R52]: It would be hard to verify just the feeder parameters by using field tests or measurement data from these feeders. This scenario can fall under the method for checking model parameters of the composite load record.

In scenarios where the aggregate feeder needs to be represented explicitly (i.e. outside the composite load model), this would break away from the current modeling practices, and would be covered under adjustments to models to verify measurements at the T-D interface.

Commented [MP54]: We need to make sure that the terminology for what is modeled as UDER and what is modeled as RDER be harmonized with the modeling sub-group.

Commented [JS55R54]: Both documents use the Coordination team's definitions for modeling with one notable exception that Reigh Walling brought up. If it makes sense for a U-DER to be modeled as R-DER if some of the installations are across long impedances. This deviation is an explanation of engineering judgement when it does not make sense to model alongside other closer U-DER.

Commented [JS56]: Need to genericize the figure (not just Solar PV) – Pubs, can you assist?

Commented [BM57]: Is this recommending different measuring devices for the sole purpose of validating models? Please clarify

Commented [JS58R57]: We are recommending that devices be placed for the purpose of verifying models; however, we encourage entities to coordinate to accomplish as many tasks as needed for this device. This content describes the verification aspect.

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- Active power (W)
- Reactive power (~~VARS~~Vars)
- ~~Apparent power (VA)~~

Measurement devices used for DER dynamic model verification for both U-DER and R-DER should be capable of collecting the following data:

- ~~Instantaneous voltage (V)~~
- ~~Instantaneous current (I)~~
- RMS[24] voltage and current (Vrms, Irms)
- ~~RMS current (Irms)~~
- Frequency (Hz)
- Active power (W)
- Reactive power (~~VARS~~Vars)
- ~~Apparent power (VA)~~
- Harmonics[25]
- Protection Element Status
- Inverter Fault Code

DER monitoring equipment systems should be able to calculate ~~and~~ or report the following quantities in addition to the measurements described above:

- Power Factor (PF)
- Apparent Power (magnitude and angle)
- Positive, negative, and zero sequence voltages and currents
- Instantaneous voltage and current waveforms as seen by the measurement device

Based on the types of measurements desired, preferred, and helpful, Table 1.1 provides a summary between the steady-state and dynamic recording devices. Each of the measurements above is categorized in Table 1.2 as necessary, preferred, or helpful to assist in device selection. For dynamic data capture, Digital Fault Recorders (DFRs) and distribution Phasor Measurement Units (PMUs) are two high resolution devices that are useful in capturing transient events, but are not the only devices available to record these quantities. In some instances, already installed revenue meters may provide this RMS information[26].

Table 1.1: Recording Device Summary

Topic	Steady-State	Dynamic
R-DER		
Useful Location(s) of Recording Devices	High-side or low-side of T-D transformer(s); individual distribution circuits[27] (see Figure 1.1)	

[24] References to RMS here are fundamental frequency RMS.

[25] These measurements should collect the Total Harmonic Distortion (THD) and Total Demand Distortion (TDD) at the T-D interface. These levels should be consistent with IEEE standards (IEEE std. 519 for example) and such standards refer to the upper harmonic boundary for measurement.

[26] These devices can also offer different measurement quantities as well. See Chapter 6 of NERC's Reliability Guideline on BPS connected inverter devices here. While DERs are different in treatment of performance, the measurement devices discussed there can be used on the high side of the T-D transformer for similar data recording

[27] individual distribution circuit data is not necessary but can be useful either in addition to or in replacement of T-D transformer data

Commented [BM59]: Is it really necessary to specifically measure the kVA/MVA of a unit if you are also measuring the active and reactive power? Also, is this just the magnitude or both the magnitude and angle of the kVA/MVA?

Commented [BM60]: A Positive Sequence RMS dynamic model would not need instantaneous V/I measurements. I do agree that an EMT model would though. Can we clarify this?

Commented [JS61R60]: Moved to calculate/report section to clarify these are not needed to verify positive sequence RMS dynamic models.

Commented [PSJ62]: It may be good to include the minimum sampling rate of the measurements required to do the verification.

Commented [JS63R62]: We left out sample rate as it is up to the entities decision for these measurements. TPs/PCs should be cognizant of the sample rate to see if the measurement is suitable for the type of verification used. (i.e. not using 10 minute data for dynamic verification).

Commented [RD64]: Three phase or single phase? Or as applicable?

Commented [JS65R64]: As applicable, determined under the coordination of transmission and distribution entities' needs.

Commented [BM68]: Same question as above.

Commented [JS69R68]: See response to comment above

Commented [RD66]: Fundamental frequency RMS or true RMS?

Commented [JS67R66]: Added footnote to clarify

Commented [BM70]: Should we specify out to which harmonic? I think there was discussion before that an IEEE standard requires designing out to the 50th harmonic but someone was having problems with even higher harmonics. I may be mis-remembering though.

Commented [JS71R70]: Added footnote to reference IEEE std 519 for harmonics. SPIDERWG Verification subgroup emphasizes that transmission entities and distribution entities should coordinate to ensure that needs are met with the recording device. As a device that stops at 50th harmonic may be suitable in some ...

Commented [RD72]: Up to which order? And on which side ...

Commented [DK(TD-173R72]: Agreed. The harmonic ...

Commented [JS74R72]: See response to above comment

Commented [PM75]: Should we require harmonic ...

Commented [JS76R75]: See above comment

Commented [DK(TD-177]: For event oscillography capture ...

Commented [JS78R77]: Added "systems" to allow for ...

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Examples of Recording Devices	Resource side (SCADA) or demand side (~~,~~ Advanced Metering ~~System~~ Infrastructure (AMI~~S~~)) devices	DFR, distribution PMU, or other dynamic recording devices.
Minimum Set of Measurements	Active Power, Reactive Power	Frequency, RMS Voltage, Active Power, Reactive Power
Additional Preferred Measurements	RMS Voltage	RMS Currents
Measurements Helpful if Available	Frequency, Apparent Power, Steady-State Current	Harmonics
U-DER		
Useful Location(s) of Recording Devices	Point of interconnection of U-DER; distribution substation feeder to U-DER location; aggregation point of multiple U-DER locations, if applicable (see Figure 1.1)	
Examples of Recording Devices	DP SCADA or AMS; DER owner SCADA	DFR, distribution PMU, modern digital relay, or other dynamic recording devices[28].
Minimum Set of Measurements	Active Power, Reactive Power	Frequency, RMS Voltage, Active Power, Reactive Power
Additional Preferred Measurements	RMS Voltage	RMS Currents
Measurements Helpful if Available	Frequency, Apparent Power, Steady-State Current	Protection Element Status, Harmonics, ~~Fault~~ Disturbance Characteristics[29]; Sinusoidal Voltage and Currents

In regards to protection quantities, the identified U-DER protection device statuses coupled with an inverter log from a large U-DER device helps in determining what protective function impacted the T-D interface and to verify that such performance is similar in the TP's set of models. This type of information become more important to understand as penetration of large DER increases in a local area, especially if such protection functions begin to impact the T-D interface.

Steady-State DER Data Characteristics

As Table 1.2 summarizes the measurement quantities needed, preferred, and helpful if available, entities that are placing recording devices will need to decide upon the sample rate and other settings prior to installing the device. Table 1.2 summarizes the many/ aspects related to utilizing steady-state data for use in model verification. As the steady-state initial conditions feed into dynamic transient simulations, the steady-state verification process feeds into the dynamic parameter verification process. With the focus on BPS events, the pre-contingency operating condition and the dynamic disturbance recordings captured during these events can be used for steady-state and dynamic model verification. This is a unique process different from steady-state verification of seasonal cases in the base case development process. The considerations in Table 1.2 can be applied to both seasonal case verification as well as pre-contingency operating condition verification.

[28] For wide-area model validation, the outputs from these devices should be time synchronized, such as by GPS.

[29] This can be a log record from a U-DER characteristic, or a record of how certain types of inverters reacted to the BPS fault. This is different from event codes which are applied from the BPS perspective and including this information can assist with both root cause analysis as well as verification of aggregate DER settings.

Commented [SR79]: Inverter data?

Commented [JS80R79]: Added clarification on what is referred to by this term.

Commented [BM81]: Same question as above about the kVA/MVA

Commented [JS82R81]: See response above, here we are highlighting the helpfulness of this measurement and contrasting it with the minimum set (of P and Q).

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Commented [DK(TD-183]: Modern digital relays also come with PMU capabilities and can be enabled for data streaming. PQ meters and digital relays have event reporting capability for event analysis.

Commented [JS84R83]: Added to list

Commented [PM85]: its fairly easy to convert sinusoidal currents to RMS. Also since we need the fundamental frequency RMS it may be better to have actual sinusoidal measurements and convert them to RMS

Commented [JS86R85]: Added to helpful if available items.

Commented [DK(TD-187]: GSP timing would be useful for wide-area validation studies.

Commented [JS88R87]: Added to list. Also, assuming GPS instead of GSP.

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Table 1.2: Steady State DER Model Verification Data Considerations	
Topic	**Key Considerations**
Resolution	High sample rate data is not needed for steady-state model verification. For example, one sample every 10 minutes, can be sufficient.[30] SCADA data streams come in at typically 2 to 4 seconds per sample~~.~~; however, these speeds are not always realizable.
Duration	Largely, a handful of instantaneous samples will verify the dispatch of the DER and load for each Interconnection-wide base case. Further durations nearing days or weeks of specific samples may be needed to verify U-DER control schemes, such as power factor operation, load following schemes, or other site-specific parameters. For these, TPs and PCs are encouraged to find an appropriate duration of data depending on their needs for verification of their steady-state models.
Accuracy	At low sample rate, accuracy is typically not an issue. Measured data should have relatively high accuracy and precision. Data dropouts or other gaps in data collection should be eliminated.
Time Synchronization	Time synchronization of measurement data may be needed when comparing data from different sources across a distribution system (or even across feeder measurements taken with different devices at the same distribution substation). Many measurement devices have the capability for time synchronization, and this likely will become increasingly available at the transmission-distribution substations. In cases where time synchronization is needed, the timing clock at each measurement should be synchronized with a common time reference (e.g., GPS)[31] to align measurements from across the system.
Aggregation	Based on the modeling practices for U-DER and R-DER established by the TP and PC,[32] it may be necessary to differentiate DERs for the purposes of accounting in the power flow model. This includes separating out the MW values for U-DER and R-DER and having sufficient measurement data to capture each type in aggregate.
Dispatch Patterns and Data Sampling	Different types of DERs are often driven by external factors that will dictate when these resources are producing electric power. For example solar PV DERs provide cyclic energy during times of solar irradiance, wind resources provide output during times of increased wind, and BESSs may inject~~or~~ or consume energy based on market signals or other factors. In general, these recommendations can apply to sampling measurements for these resources: • Solar PV: Capture sufficient data to understand dispatch patterns during light load daytime and peak load daytime operations; nighttime hours can be disregarded since solar PV is not producing energy during this time. • Wind: Capture output patterns during coincident times of high solar PV output (if applicable), as well as high average wind speeds. • BESSs: BESSs should be sampled during times when the resource is injecting and during times when the resource is consuming power.

Commented [BM89]: Shouldn't this say "2 to 4 samples per second"?

Commented [JS90R89]: No. See comment below, these timeframes were provided and checked by Verification subgroup to be valid.

Commented [JN91]: This is not always the case. Some scada measurements only come in every 15 minutes due to being connected via cellular.

Commented [JS92R91]: Based on Verification discussions, these were the time bands TPs said their SCADA steam had. Added clarification that these speeds are not always the case

Commented [PSJ93]: Correct spelling from injector to ***inject***

Commented [JS94R93]: Change made as suggested

30 The resolution needs to be able to reasonably capture large variations in power output over the measurement period.
31 https://www.gps.gov/
32 https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf

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Post-Processing	Depending on where the measurement is taken some post-processing will need to be done to determine if the DER is connected to point on transmission that is not it normal delivery point. Not taking this into consideration makes DER mapping to BES model susceptible to inaccurate DER connection points. These same mappings apply to the dynamic model verification process.
Data Format	Microsoft Excel and other delimited data formats are most common for sending or receiving steady-state measurement data. Other forms may exist, but are generally also delimited file formats.

Verifying ~~operating~~ the operation mode for DER ~~voltage and current~~ may require more complex measurements and it is best to work with the applicable entities that may govern DER interconnection requirements and the DP to determine the best placements of devices to verify BES interaction characteristics. It is beneficial to include steady-state current and voltage waveforms to this effect, especially for inverter-based DER.

Dynamic DER Data Characteristics

Dynamic recorders uses in capturing the transient conditions of an event have differing data considerations than the steady-state recorders. The data characteristics and considerations typically discussed in dynamic recording of measurements are found in Table 1.3. In comparison to steady-state measurements, dynamic data measurements require a faster ~~sample~~ sampling rate with the trade-off that the higher fidelity sampling is only for a shorter time period. The data captured from dynamic disturbance recorders can be used for the purposes of dynamic model verification.

Table 1.3: Dynamic DER Model Verification Data Considerations

Topic	Key Considerations
Resolution	~~The RMS positive sequence, fundamental frequency dynamic models use a time step on the order of one-quarter of an electrical cycle.~~ Typically, the BPS planning models look at responses of less than 10 Hz, so the sampling rate of the measuring devices should be adequate to capture these effect. Therefore, ~~measurement data for DER dynamic model verification should have a resolution~~ a resolution on the order of 1-4 milliseconds is recommended to be above the Nyquist Rate for these effects. ~~[33]~~ For reference, typical sampling rates recording devices can report at 30-60 samples per second continuously, with some newer technologies sampling up to 512 samples per cycle on a trigger basis.

~~[33] For cases where EMT model verification is needed, much higher resolution data would be required.~~

Commented [LG95]: Why would operating voltage be needed in a steady state model? Typically, these devices for R-DER will be modeled at the voltage of the aggregation and U-DER is modelled at nameplate voltage. I would consider removing this

Commented [JS96R95]: Changes made to clarify based on group discussion with commenter.

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Commented [RD97]: The footnote is misplaced and unnecessary

Commented [JS98R97]: Deleted footnote.

Commented [JN99]: Should there be a minimum number of samples per cycle in order to detect harmonics? The reason I ask is that most PMUs and other measurement devices specify it in samples per cycle instead of milliseconds.

Commented [JS100R99]: Added some references to get samples per second and cycle for some devices.

Commented [DK(TD-1101]: For reference, typical sampling rate for DFR, PQ meters, and relays range from 4-128 points per cycle. 512 per cycle is offered by newer models.

Commented [JS102R101]: Added text for this reference.

Commented [PM103]: I think we should re-word this by saying that the model responses we want to model is in the range of <10 Hz and the sampling rate of measuring devices should be adequate to capture these effects properly. Therefore, a sampling rate of 1-4 ms is suggested.
The time step of simulation is adjustable based on the smallest time constant modeled. For a double cage IM this time constant is t'' which is 0.0021 which means the time step used internally for the cmld is at most 5.2500e-04. PSSE and PSLF does this internal time-step division.

Commented [JS104R103]: Reworded this in verification group discussions

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Triggering	Dynamic recording devices will need to have their triggers set in order to record and store their information. Some important triggers to have are such that a BPS fault is detected or that nearby protection relays assert a trigger to the device to record. This generally shows up as the following: • Positive sequence voltage is less than 88~~70~~% of ~~operating voltage~~the nominal voltage • Over-frequency~~Overfrequency~~ events[34] ~~above 60.1 Hz.~~ • ~~Under Frequency Events~~Under-frequency events ~~under a few hundred mHz below nominal frequency~~ Although higher trigger values can be used to obtain more data, some of those triggering events may not be useful in verifying the large disturbance dynamic performance of BPS models. ~~that may not be a BPS fault.~~ In the case, both R-DER and U-DER terminals are expected to ~~behave~~ have the same as electrical frequency ~~is highly pervasive in AC synchronized systems~~.
Duration	~~The duration dynamic measurements capturing DER response to grid events should generally be up to around 20 to 30 seconds. Sometimes longer windows are needed to capture the event.~~Event duration requirement depends on the dynamic event to be studied. For short dynamic events such as faults, 1-2 seconds time window is common. For long events such as frequency response, the time window can range from a few seconds to minutes. ~~.~~
Accuracy	Dynamic measurements should have high accuracy and precision, and any gaps in the recorded data should be minimized and eliminated.
Time Synchronization	Dynamic measurements should be time synchronized to a common time reference (e.g., GPS) so that dynamic measurements from different locations can be compared against each other with high confidence that they are time aligned. This is essential for wide-area model verification purposes.
Aggregation	Based on the modeling practices for U-DER and R-DER established by the TP and PC,[35] it may be necessary to differentiate DERs for the purposes of accounting in the power flow model. This includes separating out the MW values for U-DER and R-DER and having sufficient measurement data to capture each type in aggregate.
Data Format	Similar to the Steady-state data, the dynamic data formats typically come in a delimited file type such that Microsoft Excel can readily read in. If it does not come in a known Excel format, ASCII[36] files are typically used that would be converted into a file format readable in Excel. However, other files types, such as COMTRADE[37], are also widely used by recording devices and can be expected when requesting dynamic data from these recording devices.

Commented [BM105]: This seems a bit low. Would a better value be 88% to match up with IEEE 1547?

Commented [JS106R105]: Change made as suggested.

Commented [DK(TD-1107]: Frequency variation can vary from interconnection to interconnection. It is up to DPs to determine the over and under frequency thresholds

Commented [JS108R107]: Added footnote to accommodate comments from last meeting to address per Interconnection

Commented [JN109]: How would high resolution monitoring be implemented for smaller behind the meter distributed resources? At the substation level, changes in load can cause fluctuations (triggers) just as much as DER.

Commented [JS110R109]: SPIDERWG recommends this monitoring be at the T-D interface for aggregate R-DER devices. While load can perturb the measurement, that might be a good trigger for verification of the load model (opposed to the DER model). In either case, the TP/PC is made aware in the changes that these triggering events may not be useful for higher trigger values with high resolution data.

Commented [DK(TD-1111]: Only continuous recording devices like PMU and DFR can have 20-30 seconds event duration. PQ meters and relays typically have an event window less than 2 seconds.

Commented [JS112R111]: Changes were made by other commenter to account for these device limitations in continuous recording.

Commented [PM113]: this duration of measurements is typically not available from DFRs. Should we specify MicroPMU's or devices of that nature that has data logging capabilities with required resolution for long periods

Commented [JS114R113]: Changes made as suggested.

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[34] These events are typically at +/- 0.05 Hz around the 60 Hz nominal; however, this value should be altered for each Interconnection appropriately based on the amount and types of events desired to be used for BPS model verification.

[35] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf

[36] ASCII stands for American Standard Code for Information Interchange as a standard for electronic communication.

[37] COMTRADE is an IEEE standard for communications (IEEE Std. C37.111) that stands for Common Format for Transient Data Exchange

Chapter 2: DER Steady-State Model Verification

After collecting the data for steady-state model verification for aggregate DER, the first set of models to verify is generally the steady-state DER model. Please refer to the recommended DER modeling framework section, which references documents that indicate the usage of generator records for these steady-state models, for information on the modeling practices. This steady-state model feeds into many of the loadflow studies that TPs conduct, and is the starting point ~~for the dynamic transient~~around which dynamic model initialize~~s~~. Due to how it feeds into many different studies and that it is the starting point for dynamic studies, it will generally be the first stage of verifying the DER model.

System Conditions for DER Model Verification

System Conditions for DER Model Verification Steady state verification procedures can use slower data records and does not need events to verify the steady state data. An example of this is that other studies can provide an insight into the local region. When conducting short circuit studies, an entity found that an aggregation of DER was incorrectly modeled. In this scenario the aggregation occurred with R-DER and was modeled on the nearest BPS bus and not modeled at the correct voltage level. This was affecting the powerflow solution at the modeled BPS transformer and cause increased LTC activity in the powerflow model. The entity solved the issue in their studies by verifying the location of the resource, the connection voltage, and analyzed its path the BPS bus to get appropriate impedances between the R-DER and BPS transformer. It is recommended that other entities utilize this approach where appropriate to create an accurate steady-state DER model~~Steady state verification procedures can use slower data records and does not need events to verify the steady state data. An example of this is that other studies can provide an insight into the local region. When conducting short circuit studies, an entity found that an aggregation of DER was affecting the powerflow solution at the modeled BPS transformer when the solution software was behaving abnormally. The entity solved the issue in their studies by verifying the steady state aggregate DER model and it is recommended that other entities utilize this approach where appropriate~~.

There are a few conditions that the TP should ensure is verified in their set of models and each is to be verified systematically when the data becomes available. A set of important conditions to verify, accounting for gross demand and aggregate DER output, include the following[38]:

- DER output at a (gross or net) peak demand condition
- DER output at some off-peak demand condition

At each of these points, the collected active and reactive power will help verify the steady-state parameters entered into the DER records. ~~Voltage and frequency data~~Voltage measurements will also help inform how the devices operate based on the inverter control logic, voltage control set points, and how ~~that~~ these aggregate~~s~~ to the T-D interface.

If the daily load trend is looking differently in the local area, the TP or PC is encouraged to review their load model validation procedures to determine the attributable jumps, discontinuities, or trends that may be due to DER as opposed to demand. TPs and PCs are encouraged to develop a DER model validation process for those system conditions such that the jumps, discontinuities, and trends of the DER are incorporated in the set of planning models appropriately.

[38] These examples are used to be in alignment with the conditions in TPL-001-4 (link: here)

Commented [BM115]: This document refers to the steady state model fairly often but it doesn't actually define what a steady state model consists of (IE a negative load or an explicit generator). I don't think it is in the scope of this document to lay out the DER model but it should point to where the preferred definition of a steady state or dynamic DER model is housed.

Commented [JS116R115]: Added another sentence to refer to introduction section that contains the links and framework. Highlighted key point of explicit generator records.

Commented [BM117]: Not sure the end of this sentence makes sense. Maybe revise to "and is the starting point around which dynamic models initialize"

Commented [JS118R117]: Change made as suggested.

Commented [RD119]: This is not at all useful unless either a reference is provided or more information is provided.

Commented [JS120R119]: Information provided per comment above.

Commented [RD121]: How was it verified?

Commented [JS122R121]: Information provided per comment above

Commented [RD123]: What is the approach?

Commented [JS124R123]: Information provided per above comment

Commented [LG125]: Consider revising to "System Conditions for DER Model Verification Steady state verification procedures can use slower data records and does not need events to verify the steady state data. An example of this is that other studies can provide an insight into the local region. When conducting short circuit studies, an entity found that an aggregation of DER was incorrectly modeled. In this scenario the aggregation occurred with R-DER and was modeled on the nearest BPS bus and not modeled at the correct voltage level. This was affecting the powerflow solution at the modeled BPS transformer and cause increased LTC activity in the powerflow model. The entity solved the issue in their studies by verifying the location of the resource, the connection voltage, and analyzed its path the BPS bus to get appropriate impedances between the R-DER and BPS transformer. It is recommended that other entities utilize this approach where appropriate to create an accurate steady-state DER model."

Commented [JS126R125]: Change made as suggested, given that this was your section

Commented [LG127]: We didn't ask for frequency in steady-state before so we shouldn't mention it here.

Commented [JS128R127]: Deleted as recommended.

Commented [LG129]: Not sure how much value this provides in the steady-state realm

Commented [JS130R129]: Altered, but see Brad's comments on voltage settings in steady state records for certain conditions.

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Temporal Limitations on DER Performance

> **Key Takeaway:**
> Time dependent variables impact the dynamic capability of the DERs in the aggregation. TPs should separate maximum nameplate capacity and maximum dynamic capability during the event during dynamic model verification.

Due to a multitude of reasons, DER operational characteristics can inhibit the DER performance. For solar PV, solar irradiance inherently limits the output of the DER resource. If the irradiance is insufficient to reach the maximum output of the resource, such conditions need to be accounted for in the model verification activity. Much of the inverter control settings are still applicable for dynamic performance verification for the measured data. For instance, if the aggregate DER response was indicated to have a maximum power of 10 MW, that power has a specific ~~average~~ minimum irradiance value associated with the output of the devices. Lower values of irradiance will produce a lower associated available power to extract from the solar cells and vice versa for higher irradiance values with respect to low and high limits. Similar considerations for other resource types will be needed in order to ensure the available power from the resources is correctly determined prior to adjusting the other parameters of the model. The unavailability of such data should not stop the process as verification of other parameters can be performed.

Steady-State Model Verification for an Individual DER Model

> **Key Takeaway:**
> The large majority of U-DER facilities are s~~S~~olar PV, and behave generally like other BPS s~~S~~olar PV IBR resources. This predictable performance should be included when gathering data for model verification purposes.

The objective of steady state verification of DER installations is to verify the correlations between active power, reactive power, and voltage trends. The responses below in Figure 2.1 demonstrate how a DER device characteristics may change in the day to day responses. Compare that response with the total load response in Figure 2.2. While the data contained here demonstrates the controllability aspects of the DER resource over a long period of days, much of this data can be inferenced based off irradiance data taken close to the facilities; however, this particular site had a few controllability settings to verify, namely load following settings.

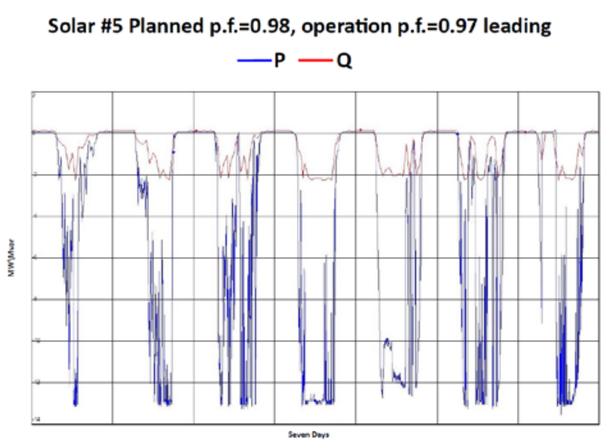

Figure 2.1: Load Following U-DER Response

Commented [BM131]: Don't know if "average" is the right word here. I think "minimum" might be better thinking of the parabolic shape of a PV profile. For a sunny day the irradiance would hit the minimum level required to output the maximum allowable power twice, once when the sun is coming up, the other when it is going down. Between those times the irradiance is higher than that needed for full output.

Commented [JS132R131]: You are right. Change made as suggested.

Commented [PSJ133]: I think the term solar PV IBR resource (in the Key Takeaway box) should be clarified. Does this refer to the inverter based resources on the bulk power system?

Commented [JS134R133]: Clarified as we are trying to make that connection in terms of the parabolic PV resource profile.

Commented [PSJ135]: Why does the power output from DER become negative? Is this the load as seen by the distribution system?

Commented [JS136R135]: It is not the load, but at the terminals of the resource, the negative value is based on that particular entity's way of tracking it (negative indicates production from the resource that could flow back to transmission system).

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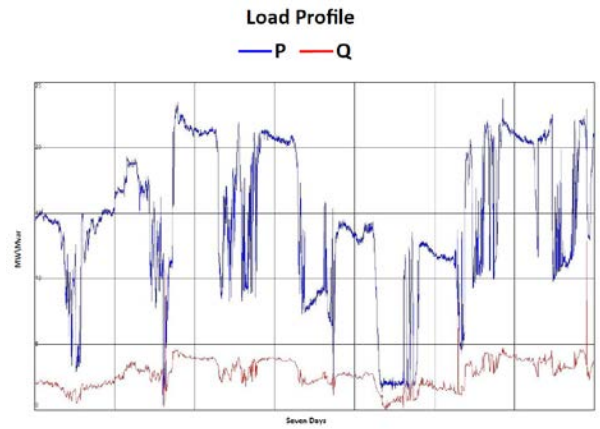

Figure 2.2: Load Response near the U-DER

In the steady state, the points required could be verified based on day 4 only. To reiterate, the P and Q relationships could be verified by simply providing that one day. To verify the load following setting, day 5 provides valuable information regarding the load following settings In addition, it is important to know that these measurements came from two different electrical locations (at the terminals of the U-DER device and at the T-D interface for the load) and such separation allows for the steady-state verification process to be easier. Each TP/PC should consult with the DP to ensure the data required to verify their facility as part of the modeled aggregation is submitted. Care shall be taken to ensure that the data will be used for its intended purpose of model verification and will not be misused or shared outside of the DPs and other distribution entities intended use; however, it is graphs like these that allow TPs to verify the P, Q, and V characteristics in their steady state models. If there isn't data measurements like Figures 2.1 and 2.2 made available, by asking questions of the DP and applicable entities, the TP is able to adjust their set of planning models to account for any changes to the DER aggregation from the submitted model. Table 2.1 highlights some of these important questions.

Table 2.1: Sample DER Steady-State ~~Data Points~~ ~~and~~Questions and Anticipated Parameters

Data Collected	Anticipated Parameters	~~Specific DER parameters~~
~~How many DER installations~~What is the aggregated operational characteristics of DERs [39] at substation within specified time domain?*	This will help set the maximum power output of all DER represented in the verification process. This ~~assumes that the count of inverters is indicative of the size of installations. i.e. 5 installations of 5 MW for a total of 25 MW~~accounts for the aggregated ~~coincidental capacity~~coincidental capacity potential of the resources.	~~Pmax~~

39 A "DER" here is be taken from the Interconnection Request. In such a request, the total MW of output is listed. That is the MW used in the summation of all "DER installations"

Commented [BM137]: Not sure what this table is specifically asking for? Steady state parameters for the powerflow model? Or just data points in general? Why list PMAX twice? The interconnection location is important as well, but maybe this table assumes one already knows where the DER is located, but not the parameters around it?

Commented [JS138R137]: Changed Table title, delete third column, and added location as a separate row. This is asking, when measurements are not available, ways to verify the steady-state dispatch of the BPS model.

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Commented [SR139]: Many interconnection issues and working groups around the country focus on the operating profiles, which is very important with AC coupled storage, so that nameplates are not simply stacked if the DERs do not operate in this manner.

Commented [JS140R139]: Changes kept to emphasize this point.

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What is the point of interconnection (i.e. transmission substation) where the aggregate DER connects to?	This will identify which load/generator record in the powerflow set of data to attribute the aggregate DER capacity and generation in the set of BPS models.	
What is the magnitude and type of aggregated coincidental load connected to the transmission substation?**	This data point will assist in determining how the overall model set will perform when adjusting both the DER model and load model at the substation.	~~Pmax, Pgen~~
What reactive capability is supplied at the DER installations?	This will assist in determining the maximum reactive output of all DER represented in the verification process. This question can also be asked of the aggregate load response.	~~Qmax, Qmin~~
Minimum power of DER***	For non-solar related DER devices such as microturbines or BESS, this parameter provides the minimum required output of the DER resource in transient stability.	~~Pmin~~

* This question is useful for BESS DERs in discharging mode
** This questions is useful for BESS DERs when in charging mode
*** This question is useful for BESS DERs regardless of charging or discharging

Battery Energy Storage System Performance Characteristics

With regard to BESS, the performance of the DER is highly dependent upon the control of the device. Understanding the operational characteristics of the BESS DER will allow the TP and PC to associate the steady-state interactions of load and the modeled BESS DER. For example, coupling U-DER BESS and other U-DER modeled Solar PV devices in the same model, care needs to be taken to ensure that the U-DER facilities are adequately represented and that the storage aspect of the model is correctly implemented. Including BESS during verification procedures may require measurement devices for aggregate U-DER BESS installations as well as other U-DER modeled DER installations. If the model verified is an R-DER BESS installations along with other R-DER, DPs and other entities may need to contact the OEM or DER developer for some of the questions in Table 2.1. It is recommended that DPs and other entities establish a good relationship with the OEMs of BESS such that steady-state BESS parameters are captured and can be highlighted in any measurement device for ~~those~~ R-DER modeled resources. Regardless of how the DER is modeled, current practices include surveys or other written means to obtain an operational profile of BESS DER, which helps validate the parameters used in steady-state analysis.

It is recommended to utilize a single DER model for aggregate U-DER, but some complexities or modeling practices may dictate otherwise. ~~A prime E~~examples for moving to ~~two~~ separate ~~models~~ aggregations is related to the frequency or voltage regulation settings. Some modeling practices aggregate each technology type separately; however, the benefit of a single DER model for each U-DER allows for a one to one relationship in any measurements provided. ~~for a DER BESS providing a load following service next to a DER facility that is at power factor control. There exists many complex control interactions between those facilities, and a single measurement location may not be able to capture all the steady-state parameters for modeling in order to capture the unique aspects of BESS opposed to other DERs.~~ The TP and PC is recommended to use engineering judgement and readily available information to determine if these ~~BESS~~ considerations are necessary for their models and alter their verification practices accordingly.

Steady-State Model Verification for Aggregate DERs

The verification of multiple facilities at they pertain to the aggregation is a more complex process than modeling a single U-DER facility due to the variety of different controls and interactions at the T-D interface ~~When there is only~~

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Commented [PM141]: Load keeps varying throughout the day. Do we need peak or off peak or coincident measurements when DER is being measured? Also how does it help determine PMAX and PGEN. This is not very clear and an example will help

Commented [JS142R141]: Addressed by adding "Aggregated coincidental" in the question. Third column of table is removed.

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Commented [LG143]: In general, I feel a diagram may be very useful here to convey what we are trying to say. There is currently a lot of things in flux with BESS and conveying the information about the characteristics and modelling intricacies can be hard to follow in text, especially to readers that have not been exposed to this.

Commented [JS144R143]: A diagram was determined in the 7/27/20 discussion to not be useful here. The information here is to address the complexity of different resource aggregations behaving differently. We call out aggregate BESS as their aggregate impact at the T-D interface is made up of charge/discharge controllers that operate, for the most part, independently of one another. The guidance remains the same: monitor large U-DER and the T-D interface. BESS just means you need to be aware of any charge/discharge interactions that can mask load or other DER output.

Commented [BM145]: Not sure this is a problem but it might be useful to discuss the type of aggregation. I think aggregating U-DER according to the WECC Solar plant modeling guideline is good, but lumping individual U-DER projects together in steady state would be a mistake since they could have different steady state voltage control schemes.

Commented [JS146R145]: Changed the following in order to accommodate this point.

Commented [BM147]: This section assumes that measured data is available on a transformer and DER level. Is this always the case?

Commented [JS148R147]: It is not always the case, but follows from the Chapter 1 placement of devices for both U-DER and R-DER modeled. We recommend each U-DER be monitored/distinguished from the R-DER and in all cases have measurements at the T-D interface.

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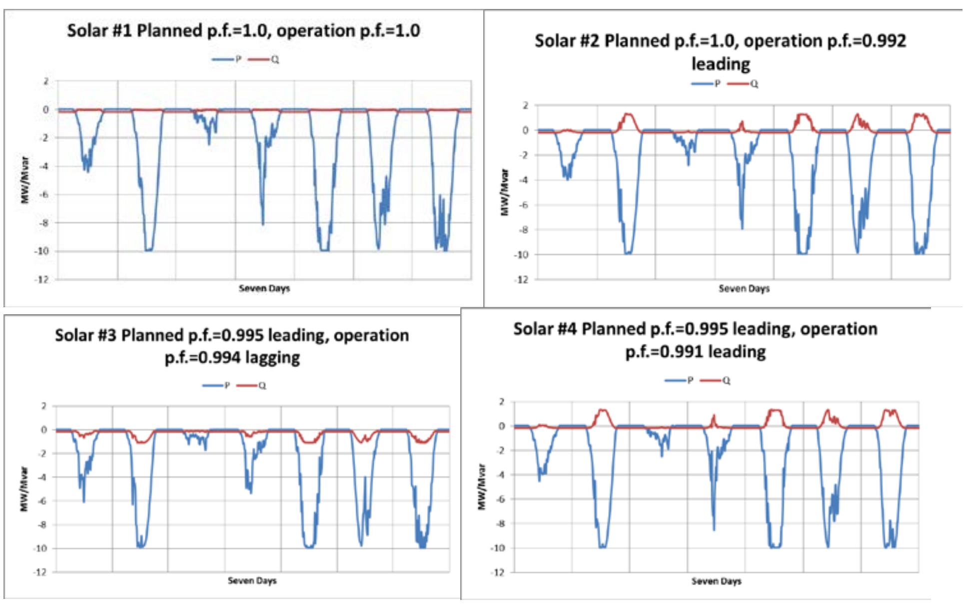
~~one large U-DER facility in the aggregate DER model the process is simpler. Adding to the complexity will be the verification of multiple facilities as they pertain to the aggregation~~. When modeling both U-DER and R-DER at the T-D interface some assumptions help the verification process. Most legacy DERs (IEEE 1547-2013) may operate at constant power factor mode only and typically are set at unity power factor, making this a safe assumption. The IEEE 1547-2018 standard has introduced more DER operating modes such as volt-var, watt-var or volt-watt and this may require reaching out to the DP to verify as the settings could be piecewise~~.~~ or the functionality may not even be used.~~.~~ More complex control schemes will require more than a cursory review of settings. Additionally, if there are any load following behaviors, it is preferable to collect each day in a week to capture load variation. It is preferable to monitor each individual U-DER location in order to aggregate the impacts of the data, while leaving the monitoring of R-DER at the high side of the T-D interface.

Commented [LG149]: Consider revising to "The verification of multiple facilities at they pertain to the aggregation is a more complex process than modeling a single U-DER facility due to the variety of different types of technologies."

Commented [JS150R149]: Slightly altered, but kept the main point as this is a transitioin sentence.

Figure 3.3 shows an example from a 44 kV feeder measurements. The four solar plants, each rated 10 MW, and one major industrial load are connected to the feeder at different locations. All solar plants were planned to operate at constant power factors at either unity or leading. The leading power factor requirement was to manage voltage rise under high DER MW outputs travel through a long feeder with lower X/R ratio. The data show that the third solar plant's reactive power output was opposite to the planned direction (lagging vs. leading). The second solar plant also could not maintain unity power factor as planned. Figure 2.3 also plots the industrial load profile and the total feeder flow measured at terminal station. Based on this, the steady state verification of the DER should reflect the aggregation of all four of those facilities as it is reflected at the T-D interface. Here, the TP is able to verify the aggregate of the U-DER solar facilities as the P and Q flows from these facilities were recorded. Additional confirmation of steady-state voltage settings would require the voltages at these locations, and is recommended to supplement these graphs.



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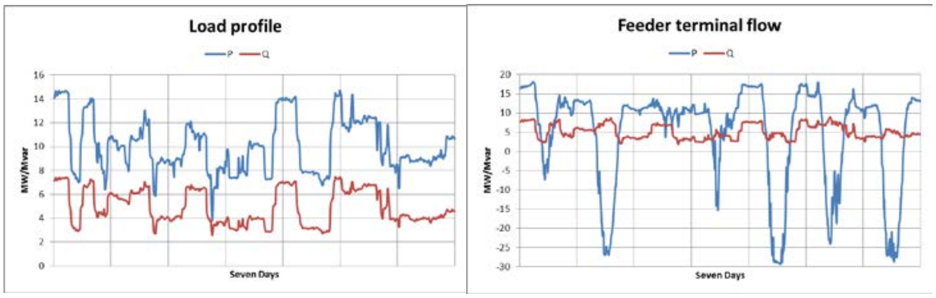
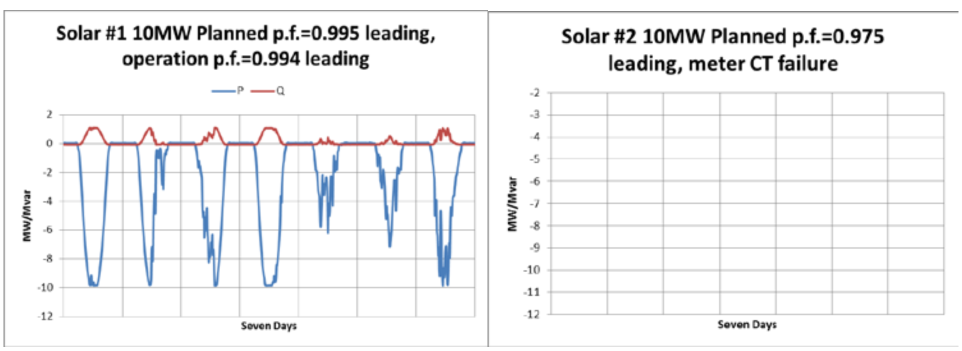


Figure 2.3: Active and Reactive Power Measurements from U-DERs, Load, and Substation

Figure 2.4 shows another 230kV station-wide measurement. Power trends from eight monitored DERs connected to 44kV feeders supplied from the station are plotted in the figure. The meter at Solar #2 was out of service in the week due to failed CT. Note the 6th solar DER is a behind the meter installation, the 7th is a biomass DER and the 8th is aggregation of three solar DERs and load[40]. The last two plots in Figure 3.4 are measured from two paralleled 230kV-44kV step-down terminals. It can be seen that nearly zero MW transferred across the transformers under high DER outputs. The Mvar flow steps were result of shunt capacitor switching at the 44kV bus of the station. Based on each of these monitored elements, the powerflow representation should capture the active power, reactive, power, and voltage characteristics as seen across the modeled T-D transformer. While not provided in the figures, the voltage at these locations should be used when verify the voltage characteristics in the model This process may require baseline measurements to determine gross load values in addition to coordination of substation level device outputs in relationship to the load and DER as evident in this example with the capacitor bank switching, DER, and load output affecting the T-D transformer.



[40] This would represent the contributions of R-DER in the aggregate DER model

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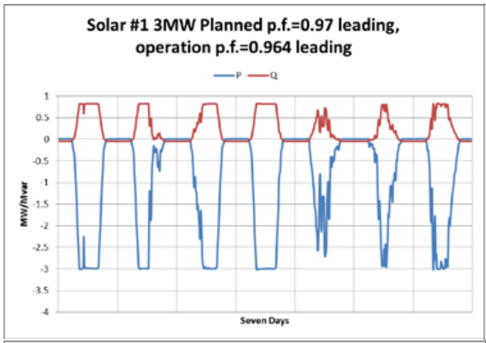

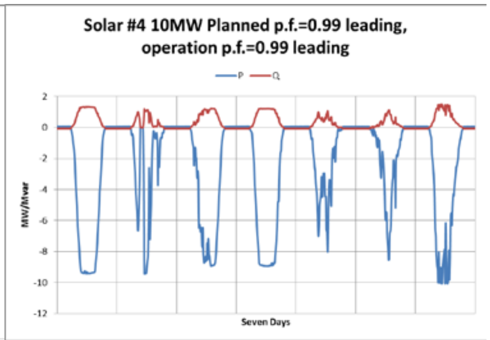

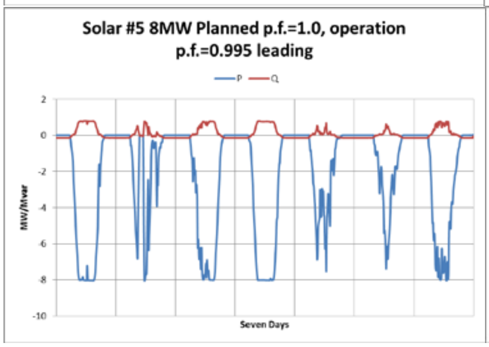

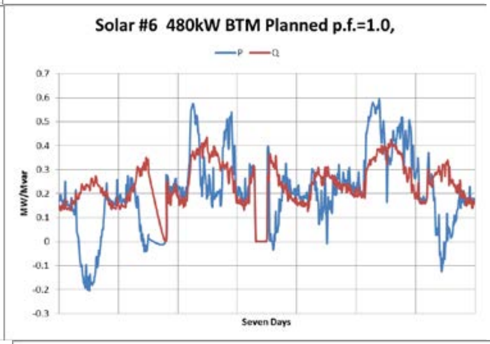

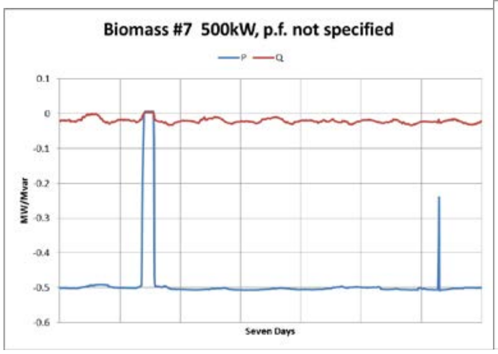

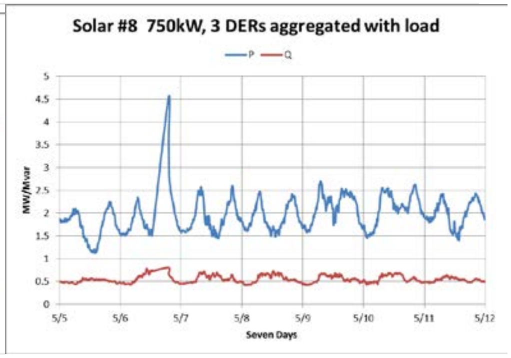

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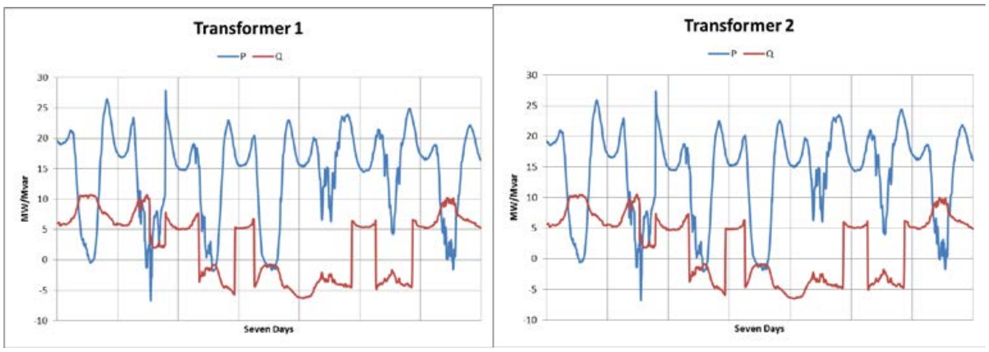

Figure 2.4 Active and Reactive Powers Measured from Various DERs and Substation Transformers

Steady-State Model Verification when R-DER and U-DER Modeled Separately

Once the model contains both aggregate U-DER and R-DER, the dispatch of the U-DER and R-DER becomes difficult to verify in the steady state records with only one measurement at the T-D interface. With measured outputs of all U-DER aggregated at the substation, a TP is able to verify the MW and MVAR output between the two aggregations so long as the gross load of the feeder is known. Figure 2.5 details a high level of the U-DER and R-DER pertaining to the distribution transformer as seen in a planning base case. Additionally, with voltage measurements pertaining to the U-DER, the whole set of active power, reactive power, and voltage parameters can be verified to perform as according to the steady state operational modes. Note that this process will inherently vary across the industry as performance and configuration on the distribution system varies. In general, the verification of the steady state P, Q, and V characteristics will need measurements of those quantities and which of the DER model inputs that measurement pertains to (i.e. the U-DER or R-DER representation). As each model record represents an aggregation of DER facilities, note that more data will help refine the process. Additionally, some modeling practices have more than one generator record for different aggregations of DER technology types, namely for U-DER. The increase of generator records when modeling DER increases the importance of monitoring individual large U-DER facilities in order to attribute the correct steady state measurements to the planning models. In general, when viewing measurements from a T-D bank, assumptions will be required to categorize the U-DER response in relationship to the R-DER response

Key Takeaway:
Increasing the number of generator records when modeling DER increases the importance of having additional measurement locations.

Commented [BM151]: Again, I don't think we should recommend aggregating the U-DER's since they can have different steady state voltage control schemes. Some could be in PF control, others in voltage control. These aren't always small plants either, they can be 20-30MW's. I think U-DER steady state outputs should be verified on an individual plant basis.

Commented [JS152R151]: Added some text below to stress this modeling practice.

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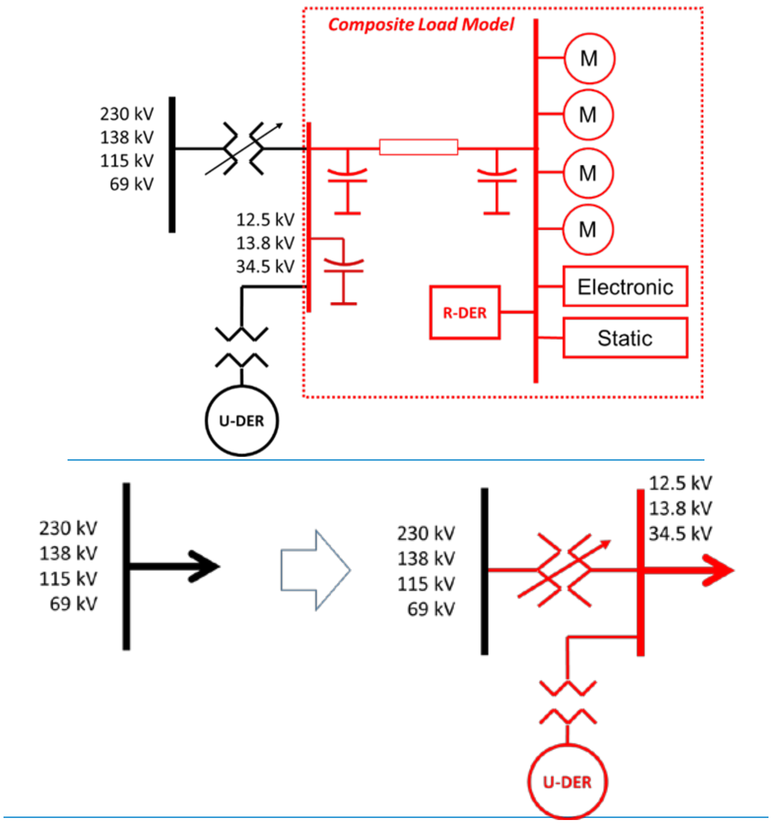

Figure 2.5 Aggregate U-DER and R-DER Steady-State High Level Representation

Commented [RD153]: The diagram does not specify R-DER. Would be good to include R-DER in the diagram. The reader may not know what the arrow at the 12.5kV bus is supposed to denote

Commented [JS154R153]: Changed figure to include both modeled types.

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Chapter 3: DER Dynamic Model Verification

This section covers the verification of the aggregate DER model for use in dynamic simulations. Generally speaking, the primary initiating mechanism for verification of dynamic models are BPS level events. Historic events may be used to verify the performance of equipment online during the event. The majority of dynamic model verification occurs when using recorded BPS level events as a benchmark to align the model performance. If the DP/TP/PC has access to the commissioning tests, the availability of these results is also useful in DER model verification as some commissioning tests demonstrate the dynamic capability of the devices.

Event Qualifiers when using DER Data

Some qualifiers should be used when selecting the types of events used in model verification due to the varying nature of events. Because of the many aspects of events, the following list should be considered when performing verification of the DER dynamic model:

- Utilization of measurement error in calculations regarding closeness of fit
- Separation ~~from~~ of DER response from load response in events, both in steady state and dynamics performance
- Reduction strategies to simplify the system measurements to the models under verification

Because of event complexity, some events simply will not have any value in verifying the DER models and thus will have no impact to increasing model fidelity. Such considerations are:

- Events that occur during nonoperational or disconnected periods of the DER
- Other events that do not contain a large signal response of DER. This is the case with very low instantaneous penetration of DER.

Even with previously verified models for one event, additional events will also provide TPs additional assurance on the validity of the dynamic DER model. One of the most telling aspects on this would be that the Event Cause Code is different between verified model and new event and such differences impact model performance. Based on the above factors, it is crucial to the model verification process that each recorded event have sufficient detail to understand the event cause and the DER response in order to link the two. Such documentation should be considered in order to ensure future procedures are beneficial to the verification of the model.

Individual DER Dynamic Model Verification

If the TP/PC determines there are sufficient amounts of aggregate DER in a study area, then models should adequately represent dynamic performance of aggregate DER. U-DER and R-DER differ in that dynamic performance characteristics of individual installations of U-DER are practically accessible, while the dynamic performance characteristics of individual installations of R-DER are not. Thus, though this section focuses on the dynamic performance of U-DER, many of the same performance characteristics may be inferred under engineering judgment to apply to R-DER[41]. With data made available, model verification can occur. See Figure 3.1 for a high-level representation of U-DER topology with load and other modeled components. The composite load model here contains a modeled R-DER input; however, in this section the composite load model is considered to not include that input.

[41] In the model framework, the U-DER facilities are connected to the low side bus of the T-D transformer as they are generally close to the substation with a dedicated feeder. In cases where this is not the case, the TP should consider moving that DER facility from the classification of U-DER to R-DER in the modeled parameters if the facility is sufficiently far away from the substation that the feeder impedance affects the performance of the large DER facility.

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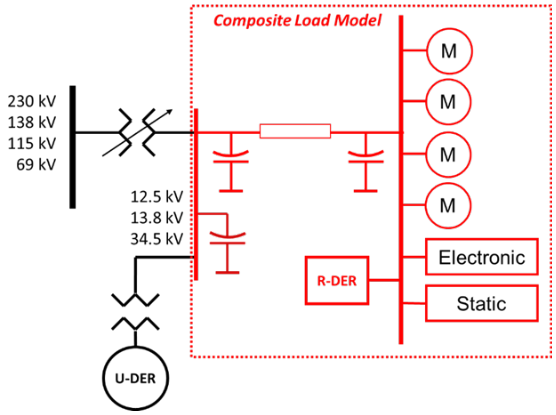

Figure 3.1 High Level Individual U-DER and Load Model Topology

Dynamic Parameter Verification without Measurement Data

In the instances where measurement data is not made available to the TP for use in model verification, the TP is capable of verifying a portion of their dynamic models by requesting data from the DP or other entities that is not related to active and reactive power measurements, voltage measurements, or current measurements. A sample list of data collected and anticipated parameter changes is listed in Table 3.1. This list of parameters is not exhaustive in nature. ~~and~~This table should be altered to address the modeling practices the entity uses in representing U-DER in their set of BPS models, and should be used only as an aide in determining those parameters required for the dynamic performance verification as the model and system changes between the initial model build and the current set of models. These parameters can be used to help adjust the model in order to assist in performing the iterative verification process. As the DER_A model is one of the few current generic models provided for representing DER, those parameters are listed to assist the process. These parameters can come from a previous model in addition to a data request. An important note is that requesting the vintage of IEEE 1547[42] inverter compliance will provide the TP information adequate to ensure their model was correctly parameterized to represent a generic aggregation of those inverters. This is especially true of higher MW DER installations as these are more likely to dominate the aggregation of DER at the T-D interface. This method is not intended to replace measurement based model verification, but rather supplement it where measurements are not currently available.

Key Takeaway:
Ensuring correctly modeled IEEE 1547 vintage through data requests allows the TP to ensure their dynamic DER model is correctly parameterized

Table 3.1: DER Dynamic Model Data Points and Anticipated Parameters		
Data Collected	**Anticipated Parameters**	**Example DER_A parameters**

[42] Or other equivalent applicable equipment standard

Commented [RD155]: Or equivalent applicable standard.

Commented [JS156R155]: Added footnote on this.

Commented [BM157]: Should this only be referring to the R-DER? I think U-DER should have their own explicit models developed using the WECC Solar Plant modeling guideline using the 2nd gen renewable models.

Commented [JS158R157]: This should be representing both R-DER and U-DER. While we understand the 2nd generation models are useful for IBR DER, this does not always mean entities will use explicit modeling of U-DER. The framework allows for aggregate models on U-DER and we want to address those here.

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What vintage of inverters represented, ?	This will provide a set of voltage and frequency trip parameters.	Voltage: vl0,vl1,vh0,vh1,tvl0,tvl1,tvh0,tvh1 Frequency: Fltrp,fhtrp,tfl,tfh
		Overall: Vrfrac
How much of DER trips during voltage or frequency events?	This data point, in combination with the data point above will help determine the total MW of capacity that trips with regard to voltage or frequency. The answer can take into account other known protection functions that trip out the distribution feeder or other equipment not related to the inverter specifications, or can represent choices made inside the vintage.	vrfrac

Commented [JS159]: Change not accepted as the verification of BPS planning models do not need to know if the inverters are compliant with current DP practices.

Dynamic Parameter Verification with Measurement Data Available

The preferred method for dynamic parameter verification is the matching of model performance with field measurement data. Per FERC Order No. 828, the Small Generator Interconnection Agreement (SGIA) already requires frequency and voltage ride through capability and settings of small generating facilities to be coordinated with the transmission service provider.[43] And per FERC Order No. 792, metering data is also provided to the transmission service provider.[44] Thus, the TP/PC have access to data for verification of U-DER dynamic performance for units applicable to the SGIA. In utilities with larger penetrations of DER, more prescriptive language may exist to supplement the SGIA. Data at the low side of the transformer provides the minimum amount of data to perform the process, but the measured data at the U-DER terminals also can provide a greater insight into the behavior of installed equipment and the TP can perform a more accurate aggregation of such resources. If the DP has data that would help facilitate the verification process and such data is not cumbersome to send to the TP/PC, the data[45] should be sent in order to verify the aggregated impact of the U-DER installations in the BPS Interconnection base case set of models.

While the SGIA provides benefits for the TP/PC in obtaining data for applicable units, not all of the DER facilities will be under the SGIA. See Table 3.2 to get an understanding of the amount of resources ISO-NE considers as DER[46]. For the representations here, the Solar PV Generation not participating in the wholesale market is 1532 MW while 858 MW participates and is SGIA applicable. In this region, reliance on the SGIA alone will only gather a third of the installed Solar PV DER. In addition, generation from other sources totals 1351 MW, which includes fossil fuel, steam, and other non-Solar renewables as the fuel source for the DER. Based on this table, roughly 22% of all DER applicable to the SPIDERWG Coordination Group's definitions would be verified if only those facilities under the SGIA would be verified. While the SGIA does play a role in the data collection, reliance on the SGIA alone could result in significant data gaps.

Table 3.2: New England Distributed energy Resources as of 01/01/2018

[43] Order No. 828, 156 FERC ¶ 61,062.
[44] Order No. 792, 145 FERC ¶ 61,159.
[45] E.g. measurements from a fault recorder, PQ meter, recording device, or device log.
[46] The full ISO-NE letter can be found here.

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DER Category[47]	Settlement Only Resource Nameplate Capacity [MW]	Demand Resource (DR) Maximum Capacity [MW]	Total DER Capacity [MW]
Energy Efficiency	-	1765	1765
Demand Resources (excluding behind-the-meter DG capacity)*	-	99	99
Natural Gas Generation	26	331	357
Generation using Other Fossil Fuels	75	268	344
Generation using Purchased Steam	-	19	19
Non-Solar Renewable Generation (e.g. hydro, biomass, wind)	523	126	649
Solar PV Generation participating in the wholesale market	810	48	858
Electricity Storage	1	-	1
Solar PV Generation not participating in the wholesale market	-	-	1532
Total DER Capacity	1436	2656	5625
Total DER Capacity/ Total Wholesale System Capability**	4.1%	7.5%	15.9%

* To avoid double-counting, demand response capacity reported here excludes any behind-the-meter DG capacity located at facilities providing demand response. Registered demand response capacity as of 01/2018 is 684 MW
** System Operable Capacity (Seasonal Claimed Capability) plus SOR and DR capacity as of 01/2018 is 35,406 MW

In current models, the composite load model may be used to represent the load record in the verification process. PC/TPs should be aware that in the composite load model there are parameters for aggregate R-DER representation. If modeling only U-DER, the DER parameters in the load model should be set to inactive. If there are R-DER impacts, a TP can use the composite load model to insert these parameters.

Aggregate DERs Dynamic Model Verification

Similarly to verifying U-DER, the model of an aggregation of U-DER and R-DER will be conducted similarly, with the same one to many concerns discussed for steady-state verification.[48] ~~.~~ Detailed in Figure 3.2 is a complex set of graphs that represent R-DER and U-DER, along with load, connected to a 230 kV substation to the response of an electrically close 115 kV three phase fault. As evident in the figure, it is only applicable to collect multiple terminal locations of

[47] Note that these categories are from ISO-NE and may not conform to the working definitions used by SPIDERWG related to DER (e.g., energy efficiency is not considered a component of DER under the SPIDERWG framework)
[48] Please see an example in *Duke Energy Progress Distributed Energy Resources Case Study: Impact of Widespread Distribution Connected Inverter Sources on a Large Utility's Transmission Footprint*, EPRI, Palo Alto, CA: 2019, 3002016689

Commented [RD160]: Can also reference EPRI Public report which showed DER_A model validation with event measurement data:

Duke Energy Progress Distributed Energy Resources Case Study: Impact of Widespread Distribution Connected Inverter Sources on a Large Utility's Transmission Footprint, EPRI, Palo Alto, CA: 2019, 3002016689

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data when more than a single U-DER installation is modeled at the substation in the aggregation to ensure adequate measurements are available for the TP to verify their models.

Under a 115 kV system three-phase fault, the entire station sees the voltage profile[49], which details a roughly 15-20% voltage sag at the time of the fault. The voltage of the 230kV substation returns to normal after the fault; however, the current contributions across the distribution transformers changes. At the 44kV yard all four solar installations rode through the fault with increased current injection during fault. The load was not reduced after the event even with it providing reduced current during the fault. Aggregated current at T3 shows total current unchanged after fault but big increase during fault. This is different from traditional fault signature as reduced current during fault is expected when the fault is outside of the station.

At the 28 kV side the two solar plants could not ride through and shut down. In addition, increased load current after fault clearing can be seen in T1/T2, which is impossible in the traditional station representation without DER. This demonstrates that the pickup of the load was across the T1/T2 transformers. Based upon this figure, it can be determined that the dynamic model parameters should reflect the response of the aggregate, and that may look different depending on how the Transmission Planner decides to model this complex distribution substation into the planning models. In summary, with metering at each U-DER[50], large load and station terminals, we have enough information for verification of the complex models that represent these DERs.

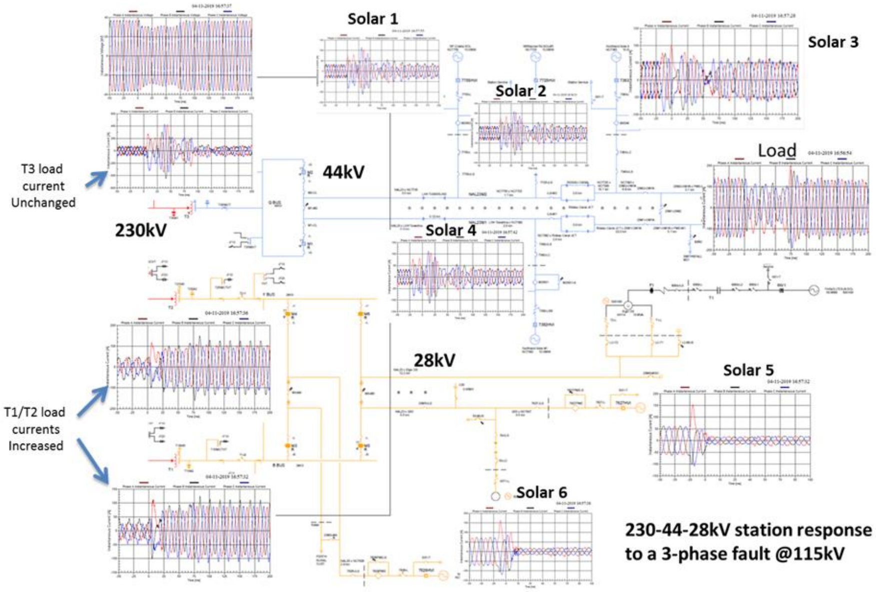

Figure 3.2: 230 – 44 -28 kV Substation Response to a 115 kV Three Phase Fault

Dynamics of Aggregate DER Models

Similar to the process for individual DER models, the aggregation of R-DER and U-DER models pose just a few more nuances in the procedure. As the framework shows, the U-DER inputs and the R-DER inputs both will feed into the substation level measurement taken. This poses a challenge where the number of independent variables in the

[49] Left top corner of the figure
[50] Note that some required monitoring at the end of the feeder

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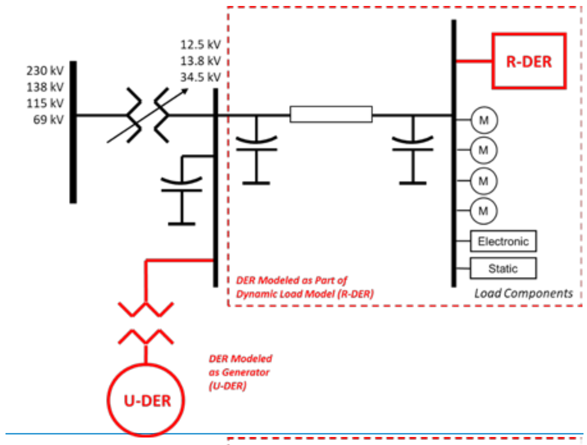
process are lower than the number of dependent outputs in the set with only one device at the T-D bank. As such, techniques that relate the two dependent portions of the model will be of utmost importance when verifying the model outputs. Figure X.X describes the overall dynamic representation of U-DER modeled DER and R-DER modeled DER with respect to the T-D interface, and Similar to Table 3.2, the same number of data points can help to verify the parameters in the DER model associated with the resource. However, a few additional points help with attributing the total aggregation towards each model as seen in Table 3.3.



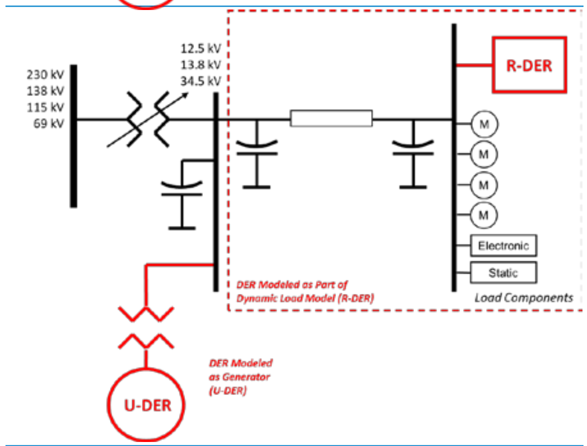


Figure X.X: Aggregate DER Dynamic Representation Topology Overview

Table 3.3: DER Data Points and Anticipated Parameters

Data Collected	Data Measurement Location	Affected Representations	Anticipated Parameters
Ratio of U-DER and R-DER inverter output*	Substation level	Relative Size of U-DER and R-DER Real Power output	Pmax in U-DER model, Pmax in R-DER model

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Ratio of DER to Load*	Substation Level	Relative size of Load model to U-DER and R-DER outputs	Pload in Load model, Pmax in DER models
Distance to U-DER installations	Substation Level to U-DER installation	Resistive loss and Voltage Drop	Voltage Drop / Rise parameters, Xe
Mean distance to R-DER installation	Substation level to calculated mean	Resistive loss and Voltage Drop	Feeder, Voltage Drop / Rise Parameters.

Notes: * This question is useful for BESS DERs regardless of charging or discharging

Most notably, the last two rows of the table detail a way to help separate the R-DER and U-DER tripping parameters and voltage profiles seen at the terminals of the inverters. Should any of the above data be restricted or unavailable, following the engineering judgments in the *Reliability Guideline: DER_A Parameterization*[51] will assist in identifying the parameters to adjust based on inverter vintages. However, the data answers in Table 4.1 are not a supplement for measurement data taken at the U-DER terminals or at the high side of the T-D transformer. With the measurements available and the data in Table 4.1, the TP or PC can make informed tuning decisions when verifying their models.

Initial Mix of U-DER and R-DER

Key Takeaway:
Relative sizes between load, U-DER, and R-DER can guide TPs and PCs on which portion of the aggregation to adjust during model verification.

In the model representation, the ratio of U-DER and R-DER is significant as the response of the two types of resources are expected to be different considering with relationship to specific voltage dependent parameters. As many entities do not track the difference in modeled DER if tracking DER at all, it is expected that the initial verification of an aggregate U-DER and R-DER model to require more than simply the measurements at the location in order to attribute model changes. TPs and DPs are encouraged to coordinate to assist in getting a proper ratio of the devices in the initial Interconnection-wide base case. In the future, there exists a possibility that the interconnecting standard for U-DER may be different than R-DER. If such standards exist, the TP/PC should verify the mix of U-DER and R-DER are representative of the equipment standards pertaining to the type of DER.

Battery Energy Storage System Performance Characteristics

With regard to BESS, the performance of both aggregate U-DER and R-DER is doubly as complicated in the BESS plus U-DER example. As highlighted in that section, control mechanisms exist that could cloud and complicate the interaction of different DER types when utilizing a singular dynamic model, but could perform adequately for steady-state DER model verification. With respect to adding in modeled R-DER and assuming retail scale connected BESS devices, it becomes even trickier to understand. Including R-DER modeled BESS devices proves to mix not only between two different DER control schemes, but also with the load. Additionally, contracts with R-DER BESS can pose challenges to obtain parameters or measurements for use in dynamic model verification[52]. It then becomes harder to separate the response of load and DER as a charging BESS system can mask increased DER output for R-DER modeled devices, and the ride-through characteristics of the aggregate BESS DER and the aggregate R-DER modeled solar PV DER can be different. In turn, model verification can become computationally complex just to attribute the response to U-DER BESS, other U-DER, R-DER BESS, other R-DER, or load in the model. TPs and PCs are encouraged to utilize engineering judgement and to coordinate with the DP and other available resources to attribute the response characteristics of load, BESS, and other DER types when performing the model verification for situations like the above.

[51] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf
[52] As many of the dynamic parameters from OEMs are largely considered proprietary

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Parameter Sensitivity Analysis

As with most models, certain parameters in the DER_A model may impact the model output depending on the original parameterization. Trajectory sensitivity analysis (TSA), a type of sensitivity analysis varying the parameters of a model, quantifies the ~~level of trajectory change from a model when small changes are made to individual parameters~~sensitivity of the dynamic response of a model to small changes in their parameters.[53] While TSA is commonly ~~used in academia,~~ implemented differently across multiple organizations, certain software packages include ~~them~~ a basic implementation. Among them are~~including~~ MATLAB Sensitivity Analysis Toolbox[54] and MATLAB Simulink. ~~In addition, EPRI is developing a tool utilizing TSA focused on load modeling.[55]~~ TSA analysis with respect to verifying DER_A dynamic model parameters can be found in Appendix A.

TSA is one of many methods for TPs and PCs to gain understanding of the sensitivity of the dynamic model to small changes in model parameters; however, this is not a required step in model verification nor a required activity for tuning dynamic models. Further, due to TSA linearizing the response of the dynamic model around the operating point, it may not account for changes in operating modes in the DER dynamic model and may not account for needed changes in flags or other control features in the model. Furthermore, some parameters in models may prove to be more sensitive than others, but are not well suited for adjustments. One such example are transducer time delays that can greatly impact the response of the device, but other parameters are more likely to be changed first. Additionally, the numerical sensitivity of particular parameters is not important for a TP to verify the aggregate DER dynamic model, but their impact on the dynamic response of the model is. It is encouraged that multiple set of parameters for DER models be tested against dynamic measurements when performing parameter analysis. ~~Therefore~~Because of all these qualifications, use of TSA should be supervised by strong engineering judgment.

Summary of DER Verification

In relationship to the verification of DER the procedures described above, some of the general characteristics are re-emphasized when performing model verification. With the purpose of taking a correctly parameterized model, the following few things are important to consider:

- Location of Voltage, Frequency, Power, or other quantity with respect to the electrical terminals of the DER devices
- Relationship of the DER devices with respect to end use demand as well as other DER devices in the aggregation[56]
- Accurate and robust metering equipment on the high or low side of the T-D transformer as well as equipment near the large DER terminals

With those three bullets in mind, TPs and PCs are encouraged to begin utilizing measurements for steady-state or dynamic model verification of DER. Since all DER generators can be tested,[57] the DER models will likely be tuned over time to represent the growth of DER in a specific area. Like BPS device models, operational considerations and adjustments are required to perform the study conditions. In order to change a verified model to the study conditions, the following items should be considered:

- Time of day, month, or year[58]

[53] Hiskens, Ian A. and M. A. Pai. "Trajectory Sensitivity Analysis of Hybrid Systems." (2000).
[54] https://www.mathworks.com/help/sldo/sensitivity-analysis.html
~~[55] https://www.epri.com/#/pages/product/3002003349/?lang=en-US~~
[56] This is particularly true of BESS DERs
[57] Nor should they be absent a technical analysis and justification
[58] Irradiance and other meteorological quantities are affected by time and some DER types are dependent upon this weather data

Commented [MP162]: For the sake of simplicity let us just call it sensitivity analysis and mention that it is the sensitivity of the entire dynamic response. This is fairly well known among transmission planners. TSA on the other hand sounds quite esoteric.

Commented [MP163]: This statement needs to be modified. This has been done extensively for the composite load model during the NERC LMTF and WECC MMWG activities by MEPPI. This is also routinely done by EPRI and other folks to identify key model parameters required for a variety of sensitivity studies. Albeit, the methods for performing sensitivity analysis is different the ones referred here.

Commented [JS164R163]: Altered to emphasize more "common" packages, but not focusing on the academic portion. Emphasized the changes of practices/implementation in entities (as evident in the comment)

Commented [MP165]: EPRI has a tool for parameter estimation called LMDPPD. However, we do not have a tool for trajectory sensitivity analysis.

Commented [JS166R165]: Removed.

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- Electrical changes between verified model and study model[59]
- Sensitivity considerations on the study[60]

Future Study Conditions

TPs and PCs should see future and other guidance from the SPIDERWG that details the study concerns with DER and how to change the model to reflect those study conditions. It is likely that not all the same parameters changed in the models to obtain a verified model will be adjusted for study conditions. For example, a study sensitivity may try and determine the impact of updating all legacy DER models on a distribution system. For such a study, tripping parameters will likely change; however, the penetration will not for that specific study. These type of considerations are not applicable when verifying the DER model; however, they are to be considered when performing a study with a verified DER model.

[59] For example, distribution system reconfiguration due to lost transformer affected the verified model, but study model has normal configuration

[60] For example, if studying cloud cover over a wide area, Solar PV DER will affected and should be adjusted accordingly

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Appendix A: ~~Trajectory~~ Parameter Sensitivity Analysis on DER_A Model

Trajectory sensitivity analysis is one of the methods to correlate the linear sensitivity of dynamic model parameters to the ~~output~~dynamic response of a~~output of the~~ model. These types of calculations can help the TP understand these relationships during the tuning of dynamic model parameters. When verifying model performance, it is crucial to understand how the parameters affect the simulation output in order to match measured quantities.

If a parameter has significant influence on the trajectory of the dynamic model output, the corresponding trajectory sensitivity index will be large. It is common for certain parameters to have a significant influence on the trajectory of a particular disturbance or system condition and negligible influence in other disturbances or conditions. Before starting the parameter calibration procedure, it is critical to identify the candidate parameters in order to reduce the computational complexity of the problem. In this study the measurement was the active and reactive power at the DER bus.

To quantify the sensitivity of parameters, a full parameter sensitivity analysis on DER_A model was carried out by performing the calculation on each of the parameters of DER_A,~~using (1)~~ and the resulting parameter sensitivity indexes are summarized in Table A.1. Simulations were performed in PSS®E and utilize one of the sample cases (savnw) as a model basis. The DER-A model was added to the system, and each of the DER-A parameters were altered by +/- 10% and the event simulated was a three phase 500 kV fault on the line between buses 201-202. Parameters of the DER_A model not listed in Table A.1 had a trajectory sensitivity of zero.~~ Simulations were performed in PSS®E~~. It should be noted that the sensitivity calculation depends on the operating point in the simulation, and that the DER_A model is an aggregated model. Both of these indicate that this calculation itself requires engineering judgement to determine if those parameters are justified to be changed. For instance, the Trv parameter is not a great candidate to change in the verification of the DER dynamic model even though it has a high sensitivity and impacts the simulation output greatly. The parameters that are good candidates to change are those that adjust the section of the dynamic performance that is needing to adjust (i.e. before, during, or after the fault) in the verification process and that the parameter under adjustment makes sense to adjust. To help illustrate this, take the Trv example in Figure A.1. While this constant has high sensitivity, it is less likely to be altered as other parts of the DER-A model that are likely to change between the initial model build and the installed equipment. Additionally, the graphical change for this calculation for Imax, Pmax, and Tiq are found in Figures A.2 to A.4, respectively.

Table A.1: Parameter Sensitivities for the DER_A model

Parameter	Value	Sensitivity	Description
Trv~~trv~~	0.02	High	voltage measurement transducer time constant
Tiq~~tiq~~	0.02	Low	Q-control time constant
Pmax~~pmax~~	1	High	Maximum power limit
Imax~~imax~~	1.2	High	Maximum converter current
Vl~~vl~~	0.49	High*	inverter voltage break-point for low voltage cut-out
Vl~~vl~~	0.54	High*	inverter voltage break-point for low voltage cut-out
vh0	1.2	High*	inverter voltage break-point for high voltage cut-out
vh1	1.15	High*	inverter voltage break-point for high voltage cut-out
Tg~~tg~~	0.02	High	current control time constant (to represent behavior of inner control loops
Rrpwr~~rrpwr~~	2	High	ramp rate for real power increase following a fault
Tv~~tv~~	0.02	High*	time constant on the output of the multiplier

* indicates this variable is affected only when the voltage trip flag (VtripFlag) is enabled

Commented [JS167]: Follow up with Shahrokh on
- Variation of the params (+/=%?)
- More detail on contingency (type of fault etc.)
- More on expected performance and setup of the analysis.

Commented [JS168R167]: Added the detail in text.

Commented [RD169]: What is this (1)? An equation?

Commented [JS170R169]: Yes, but was taken out in the review as it clouded the very generic thing we wanted to say.

Commented [RD171]: Apologies for saying this, but this entire section does not provide much information to a reader. It is too high level and there are many nuances associated with the trip parameters. Additionally, the relation of pmax and imax also includes nuances. This appendix needs to either have a lot more information or needs to be removed. In its present state, it has the potential to misrepresent information too.

Commented [JS172R171]: Adjust for aggregate model of DER Adjust for certain parameters are limits, and are not quantified by a linearized analysis.

Commented [RD173]: Apologies for saying this, but this entire section does not provide much information to a reader. It is too high level and there are many nuances associated with the trip parameters. Additionally, the relation of pmax and imax also includes nuances. This appendix needs to either have a lot more information or needs to be removed. In its present state, it has the potential to misrepresent information too.

Commented [JS174R173]: Adjust for aggregate model of DER Adjust for certain parameters are limits, and are not quantified by a linearized analysis.

Commented [JS175]: See if Shahrokh can provide a visualization of one parameter adjustment.

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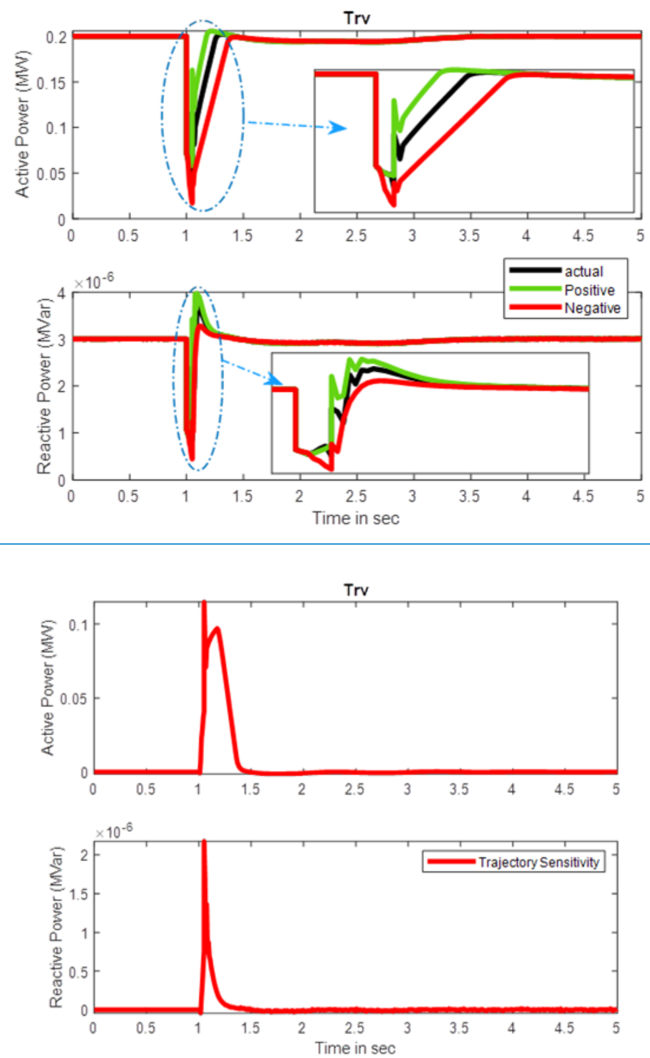

Figure A.1: Simulation Output and the Resulting TSA Calculation on Trv[61].

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[61] The reader is cautioned that this graph and following graphs are not matching measurement data to simulation output; however, it is comparing a set parameter adjustment back to the original model output for the same contingency. As expected, as you increase the time constant for the inverter to react for a voltage dip due to a BPS fault, the inverter may not see the dip in time, and decreasing the time constant means the model will react quicker to voltage changes. See the block diagram in Figure A.4 that shows the Trv constant, which demonstrates why this phenomenon exists.

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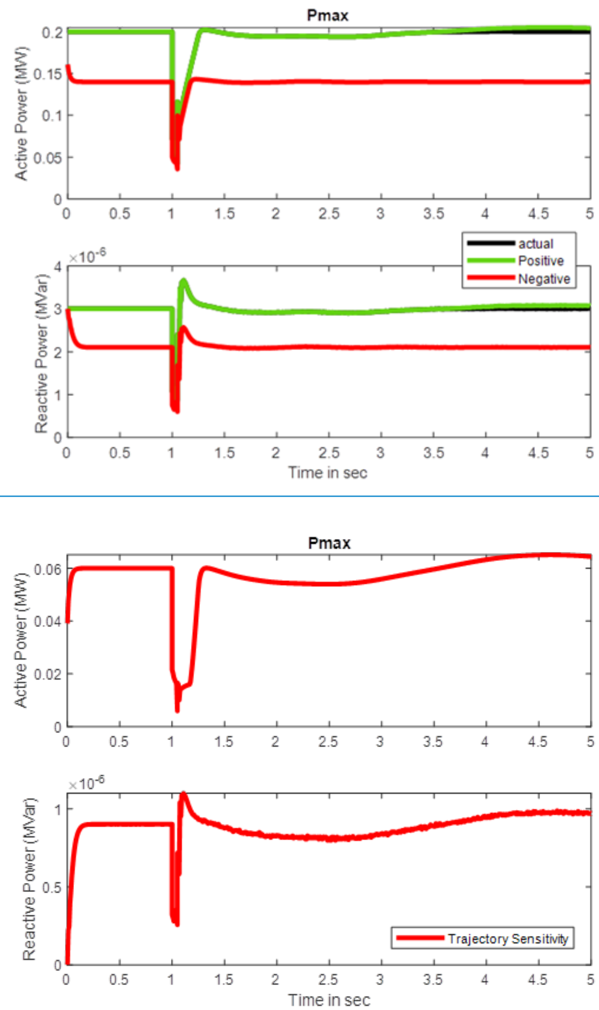

Figure A.2: Simulation Output and the Resulting TSA Calculation on Pmax.

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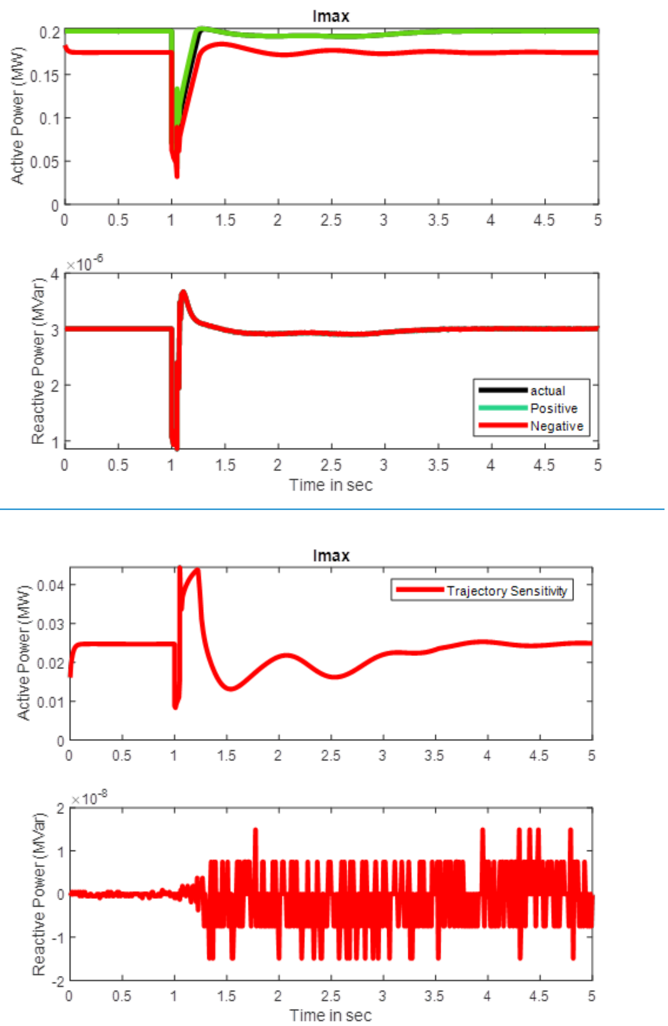

Figure A.3: Simulation Output and the Resulting TSA Calculation on Imax

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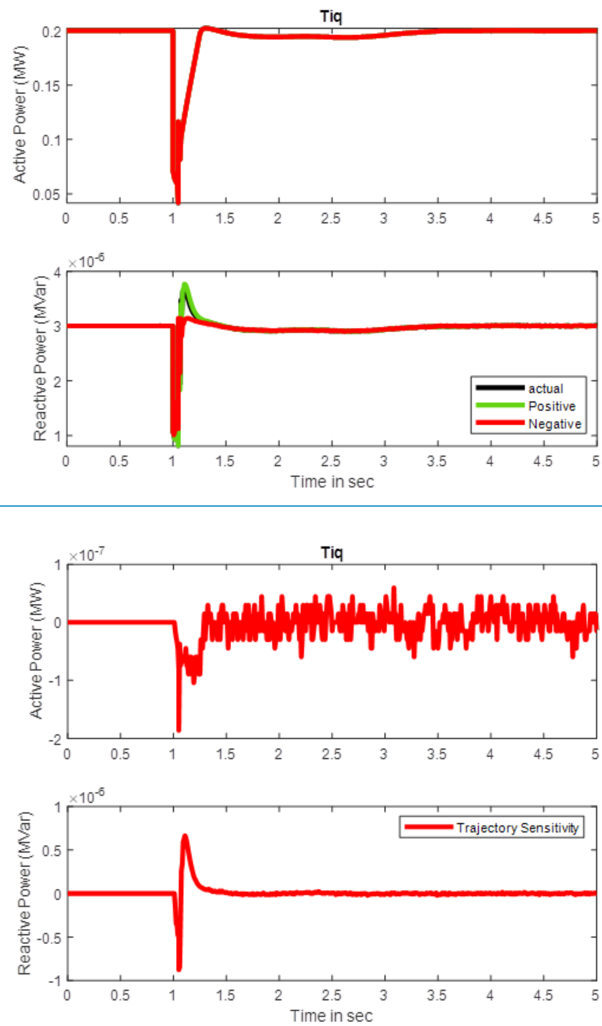

Figure A.4: Simulation Output and the Resulting TSA Calculation on Tiq.

Highly sensitive parameters have a relatively higher trajectory sensitivity and parameter values closer to zero are not as sensitive. Dynamic model control flags can affect the parameter sensitivity and therefore need to be carefully selected (e.g., PfFlag, FreqFlag, PQFlag, GenFlag, VtripFlag and FtripFlag). Figure A.5~~1~~ shows where these flags are located with respect to the DER_A dynamic model.

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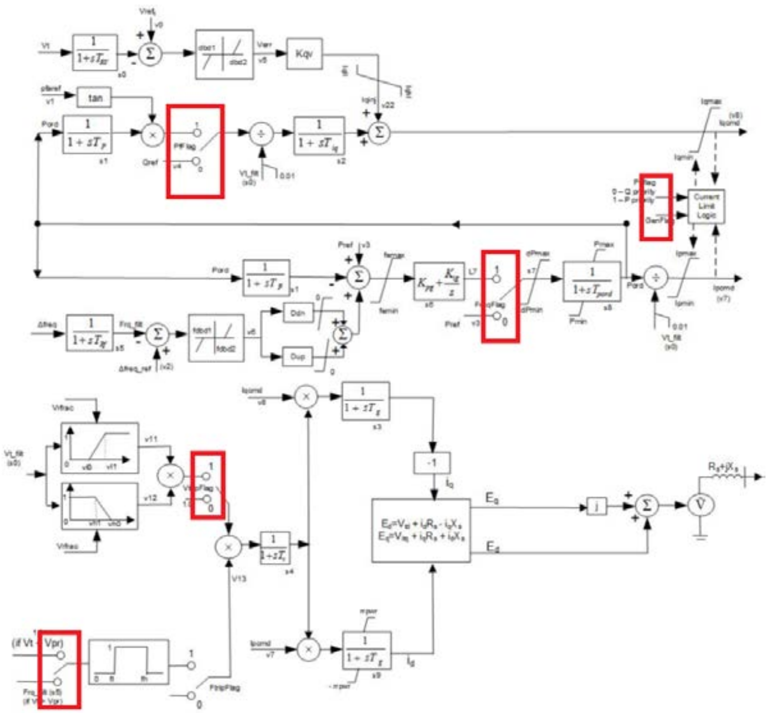

Figure A.5~~1~~: DER_A Control Block Diagram in PSS®E [Source: Siemens PTI][62]

Commented [JS176]: Levetra/pubs please help. This is getting cut off.

[62] PSSE model Documentation

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Appendix B: Hypothetical Dynamic Verification Case

To assist in developing more complex verification cases and to demonstrate how certain aspects of the Reliability Guideline stated in Chapters 3 and 4, the SPIDERWG set up a sample case with hypothetical measurements and hypothetical parameters. This appendix demonstrates the model verification starting from a common load representation. This assumes that the load record that models the distribution bank, feeders, and end use customers is represented as a single load off the transmission bus and has already been expanded to the low side of the T-D bank for dynamic model verification. A generic load expansion for that single load record is used alongside the DER_A model. The example has the monitoring device at the high side of the T-D interface, and the verification monitoring records are set up with the monitoring at that location. If the monitoring devices were on the low side of the transformer, the model results would also need to reflect that.

Commented [RD177]: If this is the case, can the obtained values of DER_A also be hypothetical?

Commented [JS178R177]: Yes

Model Setup

In Figure B.1, a Synchronous Machine Infinite Bus (SMIB) representation that describes the modeled parameters is provided. The infinite bus is used to model the contributions from a strong transmission system and is used to vary both Voltage and Frequency at the high side of the transformer; however, the measurement location is assumed to be the high side of the transformer as per the recommendations in this Reliability Guideline. The TP/PC should determine the equivalent impedance in order to determine the system strength in that area. This example assumes a stiff transmission system at the load bus, modeled as a jumper.

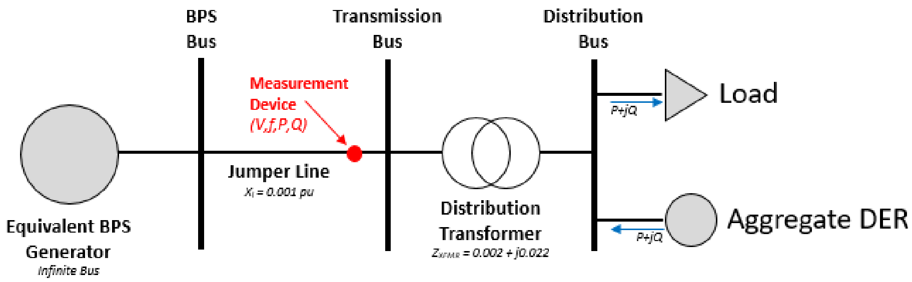

Figure B.1 Simulation SMIB Representation for High Level Aggregate U-DER

To populate the parameters in the representation, Table B.1 provides the numerical parameters assumed in the setup of the powerflow and Table B.2 contains the default parameters utilized in the composite load representation at that bus. The XFMR MVA rating is 80 MVA, and the study assumes that the transformer values have been tested upon manufacturing and is verified at the installation of the T-D bank.

Table B.1: Steady State Parameters for Study	
Input Name	**Value**
Load	60+30j MVA
Aggregate DER	10+1j MVA

In order to parameterize the Composite load model, the parameters in Figure B.2 were used and are assumed to represent the inductor motors and other load characteristics. This example is set to verify the dynamic parameters of the aggregate DER, and assumes the impacts were separated from the load response and is fully attributed to the DER. The list of parameters that were provided in the original model were is found in Figure B.2 and lists the starting set of parameters in the simulation. The supplied measurements from the hypothetical DP to the hypothetical TP were taken at the high side of the distribution transformer as indicated in Figure B.1.

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In this example, the following models[63] were used to play in and record the buses at each system. Each model was chosen to assist in either retrieving simulation data from the files, inputting measurement data, or characterizing the dynamic transient response of the load or aggregate DER in Figure B.1.

- Plnow – Used to input measurement data available for use in the dynamic simulation. Time offset of zero for using all data in the file.
- Gthev – Used to adjust the voltage and frequency at the BPS bus in order to play-in the Frequency and Voltage signals
- Imetr – Used to monitor the flows at the high end of the T-D transformer where the measurement location is. This model records P, Q, and amperage.
- Monit – Used to monitor convergence and other simulation level files when debugging software issues.
- Vmeta – Used to tell the dynamic simulation to capture all bus voltages
- Fmeta – Used to tell the dynamic simulation to capture all bus frequencies
- Cmpldw – Used to characterize the Load model
- Der_a – used to characterize the Aggregate DER model

```
#
lodrep
cmpldw     102 "LOWSIDE"  13.8  "1"  :  #9   mva=-1 /
 "Bss"   0  "Rfdr"  0.01  "Xfdr"  0.01  "Fb"  0.75/
 "Xxf"   0.00  "TfixHS"  1  "TfixLS"  1  "LTC"  0  "Tmin"  0.9  "Tmax"  1.1  "step"  0.00625  /
 "Vmin"   1.025  "Vmax"  1.04  "Tdel"  30  "Ttap"  5  "Rcomp"  0  "Xcomp"  0  /
 "Fma"   0.167  "Fmb"  0.135  "Fmc"  0.061  "Fmd"  0.113  "Fel"  0.173  /
 "PFel"   1  "Vd1"  0.7  "Vd2"  0.5  "Frcel"  1  /
 "Pfs"   -0.998  "P1e"  2  "P1c"  0.566  "P2e"  1  "P2c"  0.434  "Pfreq"  0  /
  "Q1e"  2  "Q1c"  -0.5  "Q2e"  1  "Q2c"  1.5  "Qfreq"  -1  /
 "MtpA"   3  "MtpB"  3  "MtpC"  3  "MtpD"  1 /
 "LfmA"  0.75  "RsA"  0.04  "LsA"  1.8  "LpA"  0.12  "LppA"  0.104  /
 "TpoA"  0.095  "TppoA"  0.0021  "HA"  0.1  "etrqA"  0  /
 "Vtr1A"  0.7  "Ttr1A"  0.02  "Ftr1A"  0.2  "Vrc1A"  1  "Trc1A"  99999  /
 "Vtr2A"  0.5  "Ttr2A"  0.02  "Ftr2A"  0.7  "Vrc2A"  0.7  "Trc2A"  0.1 /
 "LfmB"  0.75  "RsB"  0.03  "LsB"  1.8  "LpB"  0.19  "LppB"  0.14  /
 "TpoB"  0.2  "TppoB"  0.0026  "HB"  0.5  "etrqB"  2  /
 "Vtr1B"  0.6  "Ttr1B"  0.02  "Ftr1B"  0.2  "Vrc1B"  0.75  "Trc1B"  0.05  /
 "Vtr2B"  0.5  "Ttr2B"  0.02  "Ftr2B"  0.3  "Vrc2B"  0.65  "Trc2B"  0.05 /
 "LfmC"  0.75  "RsC"  0.03  "LsC"  1.8  "LpC"  0.19  "LppC"  0.14  /
 "TpoC"  0.2  "TppoC"  0.0026  "HC"  0.1  "etrqC"  2  /
 "Vtr1C"  0.65  "Ttr1C"  0.02  "Ftr1C"  0.2  "Vrc1C"  1  "Trc1C"  9999  /
 "Vtr2C"  0.5  "Ttr2C"  0.02  "Ftr2C"  0.3  "Vrc2C"  0.65  "Trc2C"  0.1 /
 "LfmD"  1  "CompPF"  0.98  /
 "Vstall"  0  "Rstall"  0.1  "Xstall"  0.1  "Tstall"  9999  "Frst"  0.2  "Vrst"  0.95  "Trst"  0.3  /
 "fuvr"  0.1  "vtr1"  0.6  "ttr1"  0.02  "vtr2"  0  "ttr2"  9999  /
 "Vc1off"  0.5  "Vc2off"  0.4  "Vc1on"  0.6  "Vc2on"  0.5  /
 "Tth"  15  "Th1t"  0.7  "Th2t"  1.9  "tv"  0.025
#
models
#
monit        1 "INF    "  115.00 "1 " : #9  9999.00
vmeta        1 "INF    "  115.00 "1 " : #9  0.0 0.0
fmeta        1 "INF    "  115.00 "1 " : #9  0.0 0.0 0.050000
#
plnow       1 ! ! "1 " : #9 0.0
gthev       1 ! ! "1 " : #9 .0001  .001 1 2 10 10
#
imetr     101 ! ! "1 "        1 ! !  "1 "  1 : #9 "tf" 0.0
#
#

der_a   102 "LOWSIDE" 13.8 "U " : #9 mva=11 /
"trv" 0.02 "dbd1" -99 "dbd2" 99 "kqv" 0 "vref0" 0 "tp" 0.02 "pflag" 1 /
 "tiq" 0.02 "ddn" 0 "dup" 0 "fdbd1" -99 "fbdb2" 99 "femax" 0 "femin" 0 /
"pmax" 1 "pmin" 0 "frqflaq" 0 "dPmax" 99 "dPmin" -99 "tpord" 0.02 "imax" 1.2 /
"pqflag" 1 "vl0" 0.44 "vl1" 0.45 "vh0" 1.2 "vh1" 1.19 "tvl0" 0.16 "tvl1" 0.16 /
 "tvh0" 0.16 "tvh1" 0.16 "vrfrac" 0 "fltrp" 59.3 "fhtrp" 60.5 "tfl" 0.16 /
"tfh" 0.16 "tg" 0.02 "rrpwr" 0.1 "tv" 0.02 "kpg" 0 "kig" 0 "xe" 0.25 "typeflag" 1 /
 "vfth" 0.8" "iqh1" 0 "iql1" 0
#
#
```

Figure B.2 Starting Set of Dynamic Parameters

[63] PSLF v21 was used to perform this example and the PSLF model names are listed.

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Model Comparison to Event Measurements

The event that was chosen to verify these set of models was a fault that occurred 50 miles away from the measurement location, and such fault caused a synchronous generator to trip offline. The measurements demonted here are simulation outputs from a different set of parameters and are assumed to be the reference P and Q measurement for verification purposes. For the purposes of illustration, the event is assumed to be a balanced fault[64]. The event is detailed in the first set of graphs in Figure B.3. The active power and reactive power measurements are taken at the high side of the T-D transformer corresponding to Figure B.1. In order to ensure that the load model was performing as anticipated during the event, the active powers from the load are recorded in Figure B.4, and demonstrate two separate distinctions in the process. Firstly, that the load model responds similarly between the measurement values and the reported model. Secondly, that the changes and adjustments to the DER model do not impact the response in a way that would misalign the model with the measurements.

Commented [RD179]: The previous page says that the measurements were hypothetical. Does this relate to the same sentence?

Commented [JS180R179]: yes

[64] TPs/PCs should be cognizant that unbalanced faults may not closely match the positive sequence simulation tools. This may be a source of mismatch that does not warrant modification in dynamic model parameters.

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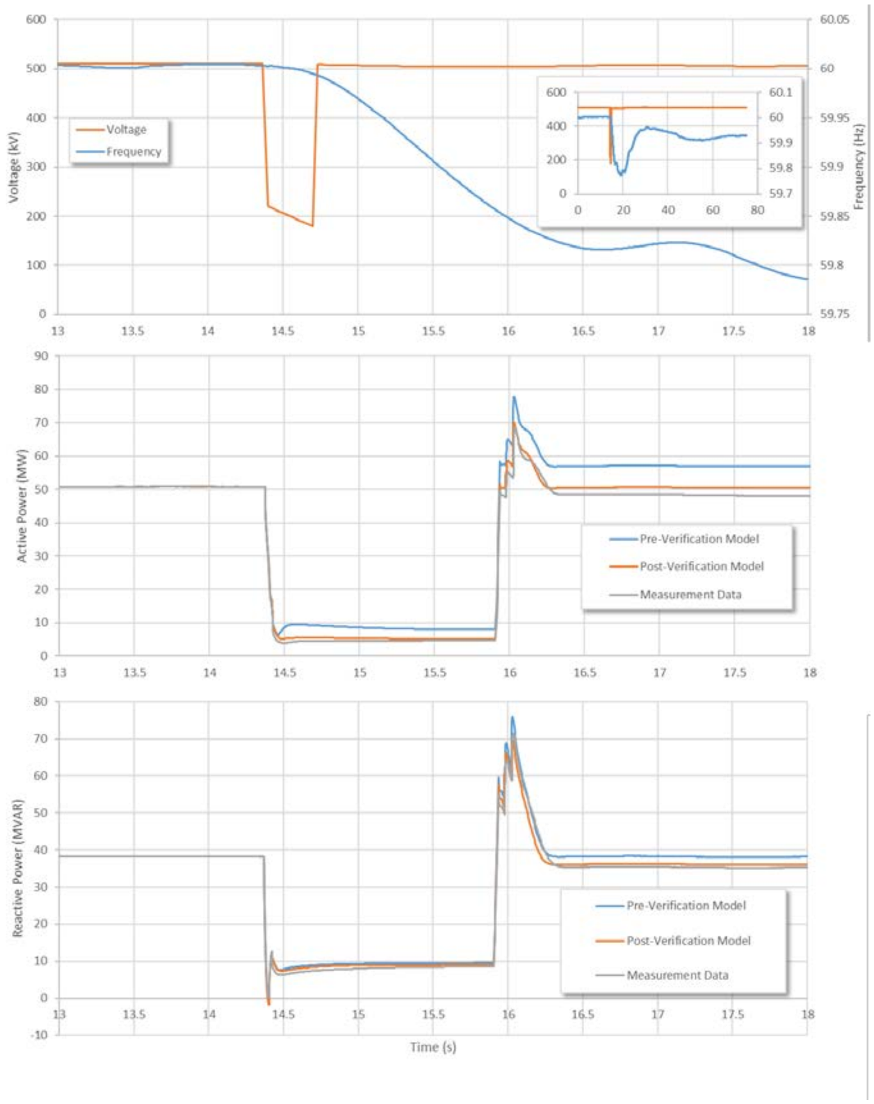

Figure B.3 Voltage, Frequency, Active, and Reactive Power Measurements

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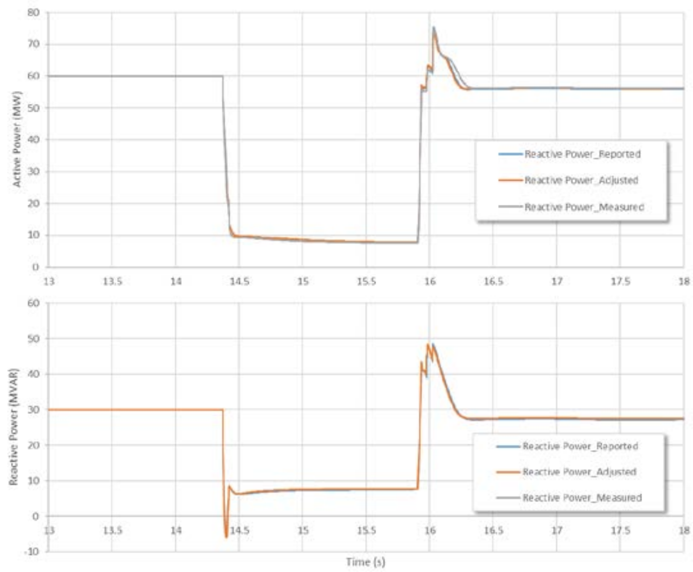

Figure B.4 Active and Reactive Power of Load Model

After demonstrating that the two active power measurements across the transformer were not equivalent, namely that the model had more active power flowing from the system into the distribution bank post disturbance as opposed to the measurements, which actually show a drop in the flow across the transformer after the disturbance. During the fault, very similar characteristics between the model and the measured power across the T-D transformer during the disturbance, yet differed primarily in the post-disturbance recovery. Based on how it seems the low voltage ride through settings seem to be too restrictive in the model, the parameters were adjusted as detailed in Table B.2.

Table B.2: DER Parameter Changes

Parameter Name	Previous Value	New Value
Vrfrac	0	0.2
Vfth	0.8	0.4
Vl0	0.44	0.35
~~Kpg~~	~~0~~	~~0.1~~
~~Kig~~	~~0~~	~~10~~
Tvl0	0.16	0.75
Tvh0	0.16	0.75

Commented [PSJ181]: Was the parameter adjustment for the DER_A model done using some optimization algorithm that minimized error between model output and measured output. A reference to the method used would be useful.

Commented [JS182R181]: All was hypothetical and no optimization algorithm was used. A simple "eye" for clarity as this was an example of what we are talking about to tuning parameters.

Commented [RD183]: The newer IEEE 1547 standard requires this to be 0.3 and it only relates to disabling frequency trip values. What was the implication of changing this value?

Commented [JS184R183]: Qualified above as everything existing in simulation based on 6/16/2020 conversation

Commented [RD185]: Initial values of 0.45 and 0.44 for vl1 and vl0 are too restrictive.

Commented [RD186]: Did this also include making the frqflag = 1 to enable the frequency control loop? What were the values Ddn and Dup?

Commented [RD187]: Did this also include making the frqflag = 1 to enable the frequency control loop? What were the values of Ddn and Dup?

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Commented [RD189]: What was the basis for changing this value?

Commented [JS190R189]: Qualified above as everything existing in simulation based on 6/16/2020 conversation

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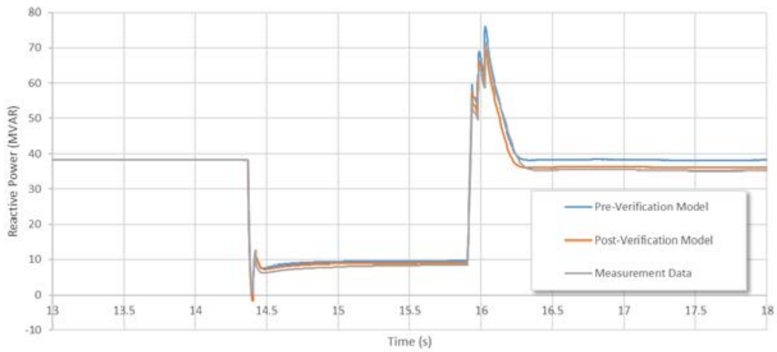

Figure B.5 Active Power of Model versus Measurements after Parameter Adjustment

After the adjustments were made in Table B.2 and simulating the model response, the active power is looked at closely, reproduced in Figure B.5, to determine the effect of the changes. Based on the closeness of fit, the verification process ends and the model is now verified against this particular event's performance. If the TP/PC determines that this verification closeness of fit is not adequate, the process would iterate again with more fine adjustments made until the entity has confidence in how the model behaves relative to the event measurements. As this process only used one event, it is highly recommended that the post-verification model be confirmed by playing back another event, if available.

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Appendix C: Data Collection Example

Specific types of BPS events have demonstrated a characteristic response in load meters, which has been attributed to DER response;[65] however, a majority of TPs or PCs may not know the types of system level measurements and practices when looking to verify a set of models. This appendix provides TPs and PCs with an example of DER response to BPS events. It also suggest methods or ideas to consider when using the event data collected for verifying aggregate DER models in planning studies.

IESO DER Performance Under BPS Fault Conditions

DER responses to transmission grid disturbances are typically not in scope of DER commissioning tests; therefore, it is more practical to verify DER dynamic performance through naturally occurred events. An example of the performance expected can be found in **Figure C.1,** which shows an example of U-DERs responding to a 500kV single-line-to-ground fault in Ontario. More than 30 DER meters recorded interruptions upon the fault and **Figure C.1** highlights seven locations as far as 300km from the fault location (voltage and current waveforms side by side, with nameplate MW indicated). The DERs were all installed under the IEEE 1547-2003; therefore, most of them tripped offline following the voltage dips induced by the fault. At Site B and Site G additional current waveforms from other solar plants connected to the same substations are included for comparison. The DER current outputs varied significantly due to different control strategies for the controllers, which experienced similar voltages at PoC.

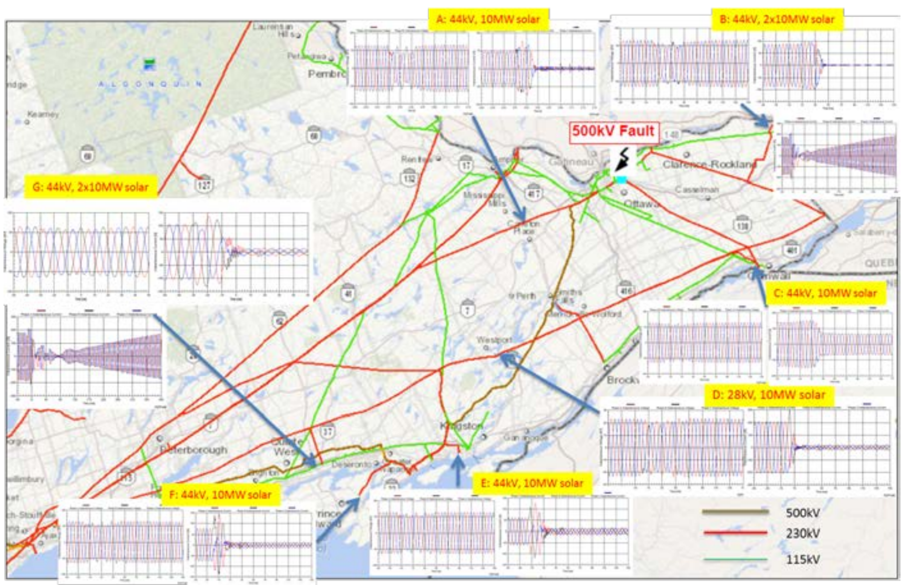

Figure C.1 Solar U-DER Voltage and Current Waveforms for a 500kV Fault

TPs can further verify the tripped loss of DER by using aggregated measurements from revenue meters at substation. **Figure C.2** plots current waveforms from one out of two paralleled 230/44kV step-down transformers at Site B where multiple solar generators are connected through the substation to 44kV feeders. The fault started near 0.0s in Figure

65 https://www.nerc.com/pa/rrm/ea/April_May_2018_Fault_Induced_Solar_PV_Resource_Int/April_May_2018_Solar_PV_Disturbance_Report.pdf

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C.2 and was cleared after three cycles. Increased net load current through the transformer can be seen after the fault clearing, which suggests most solar DERs could not recover immediately after fault clearing.

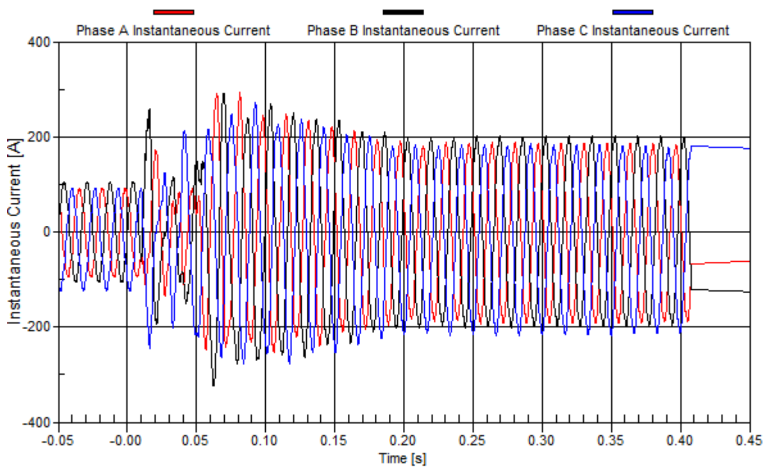

Figure C.2 Current waveforms from 230/44kV transformer at Site B

DER operating logs show various reasons that may initiate DERs shutdown, such as under/over-voltage, frequency deviations or current/voltage unbalance. A common feature associated with such initiating causes is an arbitrarily short time delay, yet some designs employ instantaneous shutdown. The IEEE 1547-2003 standard allows for protection delay settings as short as zero seconds, but such small time delays have caused premature generation interruptions under remote BPS grid events. In most cases, the DERs would have been able to ride through the disturbances if the decisions of gating off inverter were reasonably delayed.

Figure C.3 compares performances of two 44kV solar plants under a common 500kV single-line-to-ground fault. The two plants connect to the same substation bus but have different control strategies. The inverter on left side (10MW nameplate) stopped operating under voltage sag by design. The one on right side (9MW nameplate), in contrast, was configured to inject reactive current under the same voltage sag. It can be verified from Figure C.3 that the current waveforms of the two plants were very similar between -25ms and 0ms. However, the controllers made different decisions based on the information from the 25ms: the first solar plant stopped generating at t=0ms while the second one continued current injection during the BPS fault and beyond, even though they were looking at almost identical voltages at the PoCs.

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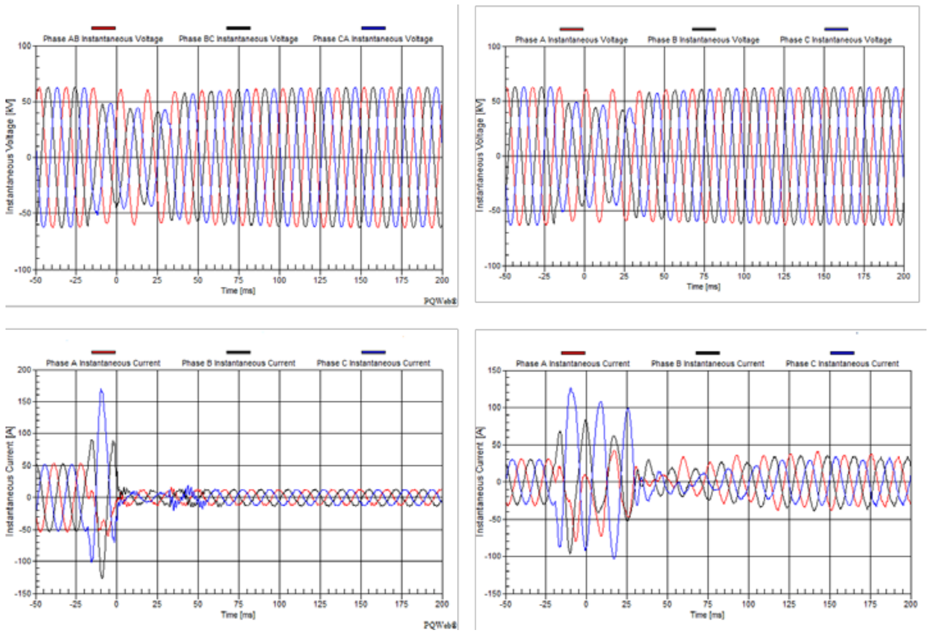

Figure C.3 Comparison of Two Adjacent Solar Plants' Responses to the Same 500kV Fault (top: voltage, bottom: current)

Installation data may suggest the overall majority of DERs are solar generators, but wind turbines connections in distribution system are also common in some utilities. Operation records show that wind DERs may experience similar interruptions as solar under BPS disturbances. Figure C.4 and Figure C.5 show Type IV and Type III wind plants responses to a common 500kV bus fault, respectively. While the wind plants are connected at different locations and voltage levels (28kV vs. 44kV), both shut down under the BPS fault. Figure A.6 shows load current increase measured from one out of two paralleled 115kV/44kV step-down transformers as a result of wind generation loss in the 44kV feeders. In this event insufficient time delay (shorter than transmission fault clearing time) for voltage protection designed under 1547-2003 was confirmed to be the cause of shutdown. Such issue is expected to diminish with the new 2018 standard revision, which requires at least 160ms time delay to accommodate transmission fault clearing.

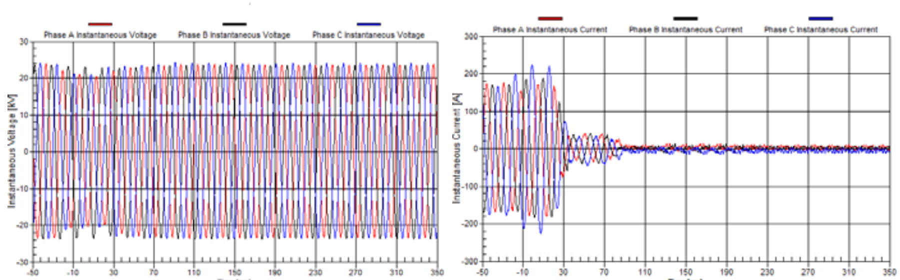

Figure C.4: Type IV Wind Plant (28kV/10MW) Response to 500kV Single-Line-to-Ground Fault

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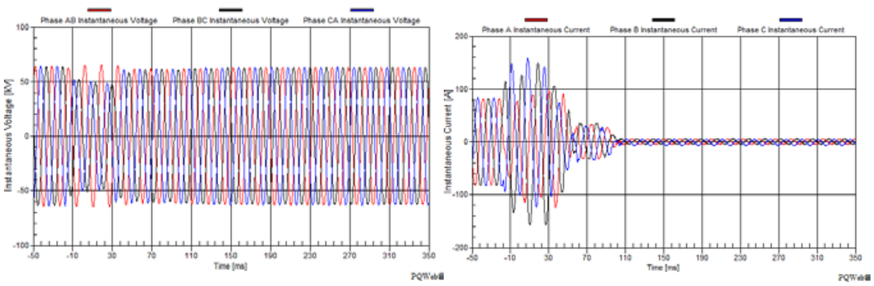

Figure C.5: Type III Wind Plant (44 kV/10 MW) Response to 500kV Single-Line-to-Ground Fault

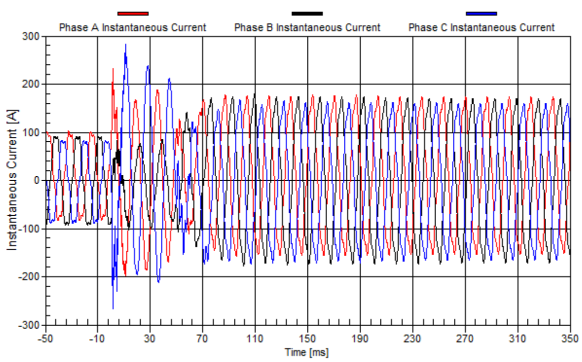

Figure C.6: Load Current Increase at a 115 kV/44 kV Transformer after Loss of Wind Generation

April-May 2018 Disturbances Findings

In the Angeles Forest and Palmdale Roost disturbances, a noticeable amount of net load increase was observed at the time of the disturbances.[66] DERs were verified to be involved in the disturbance using a residential rooftop solar PV unit captured in the Southern California Edison (SCE) footprint about two BPS buses away from the fault through a 500/220/69/12.5 kV transformation. The increase in net load identified in both disturbances signified a response from behind-the-meter solar PV DERs; however, the availability, resolution, and accuracy of this information was fairly limited at the time of the event analysis. **Figure C.7** shows the CAISO net load for both disturbances. It is challenging to identify exactly[67] the amount of DERs that either momentarily ceased current injection or tripped offline using BA-level net load quantities. Note that these measurements were taken at a system-wide level and represent many T-D interfaces, while the above IESO example is for specific T-D interfaces.

[66] https://www.nerc.com/pa/rrm/ea/Pages/April-May-2018-Fault-Induced-Solar-PV-Resource-Interruption-Disturbances-Report.aspx

[67] The ERO estimated that approximately 130 MW of DERs were involved in the Angeles Forest disturbance and approximately 100 MW of DERs were involved in the Palmdale Roost disturbance; however, these are estimated values only.

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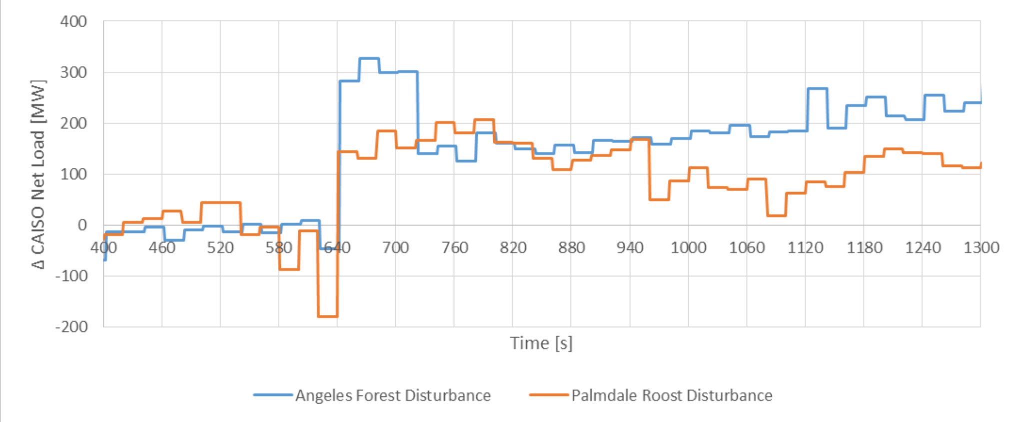

Figure C.7: CAISO Net Load during Angeles Forest and Palmdale Roost Disturbance [Source: CAISO]

SCE also gathered net load data for these disturbances (shown in **Figure C.8**). While an initial spike in net load is observed, this is attributed to using an area-wide net load SCADA point and a false interpretation of DER response during the events for the following reasons:

- The SCADA point used by SCE for area net load does not include sub-transmission generation or any metered[68] solar PV in their footprint. However, it does account for the unmetered DERs that are mostly composed of BTM solar PV.
- The SCADA point used by SCE for area net load is calculated as the sum of metered generation plus intertie imports, which includes area net load and losses.[69] Therefore, the SCADA point does not differentiate between changes in net load and changes in losses.
- As with all energy management systems (EMSs), the remote terminal units (RTUs) reporting data to the EMS are not time-synchronized. Delays in the incoming data during the disturbance can result in temporary spikes. Fast changes in metered generation (e.g., generator tripping or active power reduction) before refreshed values of intertie flow can cause the calculated load point to change rapidly around fault events. Once the refreshed values are received, the spikes balance out.

For the reasons described above, the spikes in net load were accounted for as calculation errors and variations in system losses and intertie flow changes. The temporary increase within the first tens of seconds after the fault event should not be completely attributed to DER tripping or active power reduction when using area-wide net load SCADA points. TPs and PCs, when gathering data for use in verification of DER models, should consider the bullets above when using SCADA or other EMSs when utilizing these points for verification of DER models, especially when utilizing system-wide measurements.

[68] Generally, generation greater than 1 MW is metered by SCE on the distribution, subtransmission, and transmission system.
[69] Net Load + Losses = Metered Generation + Intertie Imports

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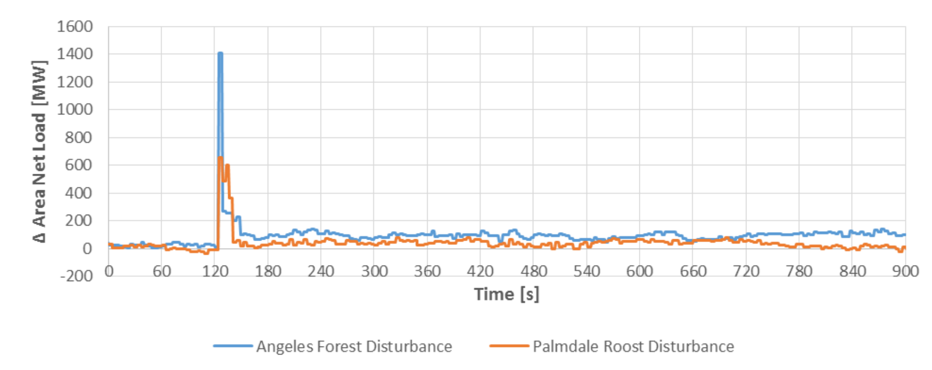

Figure C.8: SCE Area Net Load Response [Source: SCE]

It was determined that monitoring the T-D transformer bank flows using direct SCADA measurements (rather than calculated area net load values) is a more reliable method for identifying possible DER behavior during disturbances because it removes the time synchronization issues described above. Figure C.9 (left) shows direct measurements of T-D bank flows in the area around the fault. The significant upward spike does not occur in these measurements as it did in the area-wide calculation. However, it is clear that multiple T-D transformer banks did increase net loading immediately after the fault. These net load increases lasted on the order of five to seven minutes, correlating with the reset times for DER tripping as described in IEEE Std. 1547.[70] After that time, the net loading returned back to its original load level in all cases. This method of accounting for DER response is much more accurate and provides a clearer picture of how DERs respond to BPS faults. However, this method is time intensive and difficult to aggregate all individual T-D transformer banks to ascertain a total DER reduction value. TPs and PCs are encouraged to use the SCE and PG&E examples as ways to improve their data collection for DER and how to identify or attribute responses in already collected data, especially for higher impact T-D interfaces.

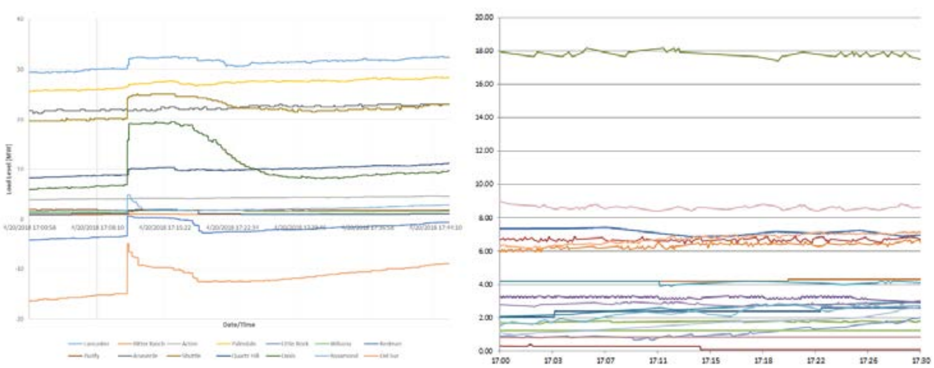

Figure C.9: SCE (left) and PG&E (right) Individual Load SCADA Points

[70] IEEE Std. 1547-2003, "IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems": https://standards.ieee.org/standard/1547-2003.html.
IEEE Std. 1547a-2014, "IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems – Amendment 1": https://standards.ieee.org/standard/1547a-2014.html.
IEEE Std. 1547-2018, "IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces": https://standards.ieee.org/standard/1547-2018.html.

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Contributors

NERC gratefully acknowledges the 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 from Distributed Energy Resources Working Group (SPIDERWG).

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Raul Perez	Southern California Edison
Jay Ramamurthy	Entergy
Steven Rymsha	Sunrun
Matthew Koenig	Continental Edison
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Brad Marszalkowski	ISO-NE
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White Paper: Assessment of DER impacts on NERC Reliability Standard TPL-001

Action
Approve SPIDERWG White Paper on Assessment of DER impacts on NERC Reliability Standard TPL-001.

Background
With the increasing penetration of DER, 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.
A subgroup was formed within NERC SPIDERWG in February 2019 to tackle this task. A white paper has been prepared and the final draft was submitted to the NERC PC for review in December 2019. Substantial comments on the white paper were received from PC reviewers in February 2020. This latest version reflects all the changes after addressing the comments received.

The 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?

The white paper addresses key findings and recommendations from the SPIDERWG review of TPL-001 regarding impacts of DER on the standard requirements and industry implementation of the standard. The intent of the white paper is to highlight potential gaps or areas for improvement within TPL-001 along with some potential solutions such that a SAR or an implementation guide can be developed, as needed, to address various issues by a SDT.

Summary
The intent of the white paper is to highlight potential gaps or areas for improvement within TPL-001 along with some potential solutions such that a SAR or an implementation guide can be developed, as needed, to address various issues by a SDT. SPIDERWG asks the RSTC to approve the white paper.

White Paper

Assessment of DER impacts on NERC Reliability Standard TPL-001
NERC System Planning Impacts of Distributed Energy Resources (SPIDERWG)
April 2020

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[1] was developed under a paradigm of predominantly BPS-connected generation, when penetrations of DERs were anticipated to be significantly lower than current and future projections, and without much impact on the BPS. Considering the current DER trend, 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 use of the term DER in this whitepaper is consistent with its description in NERC DERTF's DER Connection Modeling and Reliability Considerations report (Feb 2017)[2]. The same definition was also used in the SPIDERWG Terms and Definitions Working Document (draft) and the recently crafted MOD-032-1 Standard Authorization Request (SAR) [3] also suggested Standard Drafting Team (SDT) to consider DER definition in the NERC's glossary of terms.
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 SPIDERWG review of TPL-001 regarding impacts of DER on the standard requirements and industry implementation of the standard. The intent of this white paper is to highlight potential gaps or areas for improvement within TPL-001 along with some potential solutions such that a SAR can be developed, as needed, to address various issues by a SDT.

SPIDERWG recommends that the NERC PC review issues and that a future SDT assess the extent to which changes or implementation guidance are needed for each of these issues:

---

1 The scope of recent modifications to TPL-001-5 did not include considering the impacts of DER on BPS planning.

2 https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf#search=distributed%20energy%20resource, where DER is defined as "Any resource on the distribution system that produces electricity and is not otherwise included in the formal NERC definition of the Bulk Electric System (BES)."

3 The MOD-032-1 SAR was submitted by NERC SPIDERWG to NERC PC and endorsed by PC in December 2019. https://www.nerc.com/pa/Stand/Pages/Project_2020-01_Modifications_to_MOD-032-1.aspx

- Clarify Requirements R2.1 and R2.2 regarding use of phrase "System peak Load". This should be updated to "System peak net load", The SDT should consider whether terms should be added to the NERC Glossary of Terms for "Gross Load" and "Net Load".
- 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 DERs should be applicable to all stability simulations, not just System peak conditions.
- In developing Contingency list as required by the Requirement R3.4, an implementation guideline should be developed to identify that the Contingency list should include contingency of explicitly modeled U-DER as well.
- In considering tripping of generators in simulation as required by the Requirement R3.3.1.1, an Implementation guideline should be developed to identify that the "tripping of generators" should include tripping of DER as well. Current language in the Standard 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 DER tripping should be considered in this assessment.
- Clarify Requirements R4.1.1 and R4.1.2 regarding representing the dynamic behavior of DERs and the performance requirements applicable to 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 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. Studies of these risks should account for

  1. Updates to settings for existing and new inverters[4], and

  2. The extent to which DERs are less exposed to voltage disturbances due to the impedance of the transmission and distribution equipment located between the DERs and a disturbance on the BPS.
- Clarify Requirement R4.3.1.2 regarding the "generators" referenced in the language are inclusive of DER as the tripping of these facilities can potentially have an adverse impact on BPS stability performance.
- Clarify Requirement R4.3.2 regarding expected automatic operation of DER (e.g., DER tripping, dynamic voltage and frequency controls, momentary cessation, etc.) should be considered in stability analyses.

Table 1: Key Findings from SPIDERWG Review	
Requirement	**Key Findings and Recommendations**
R1	• This requirement **is** relevant for consideration of DER.

[4] including those that have been made in response to the September 2018 Reliability Guideline "BPS-Connected Inverter-Based Resource Performance,"(https://www.nerc.com/comm/OC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf), the September 2019 Reliability Guideline "Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources," (https://www.nerc.com/comm/OC_Reliability_Guidelines_DL/Reliability_Guideline_IBR_Interconnection_Requirements_Improvements.pdf) revisions to PRC-024-2, revisions included in IEEE 1547-2018, and any subsequent guidelines and standards revisions

	• The existing language **does not** preclude consideration of DER. • The existing language **is** clear for consideration of DER.
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 not** clear for consideration of DER.
R2.8	• 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.
R3.1	• 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.
R3.2	• 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.
R3.3	• 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.
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

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

As higher levels of DER are integrated across the Bulk Power System, DER should be part of system modeling. DER is included in R1.1.5 (“Resources (supply or demand side)”). DER data collection is consistent across the standards to reinforce the current understanding and need for inclusion of DER in BPS models used for planning assessments. While no specific threshold for DER modeling is suggested, each entity should keep track of 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 DER should be accounted for in the system model. Several other NERC Reliability Guidelines detail how the DER should be modeled.[5,6,7] For R-DER, it is sufficient to model the 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 SPIDERWG is seeking to include DER information as a necessary modeling component for BPS planning assessments. The SAR seeks 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

[5] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_DER_Modeling_Parameters_-_2017-08-18_-_FINAL.pdf

[6] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_Modeling_DER_in_Dynamic_Load_Models_-_FINAL.pdf

[7] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf

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.

R2.1.4. 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 P0 and 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 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.

R2.1.5. 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 P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

SPIDERWG Review Finding

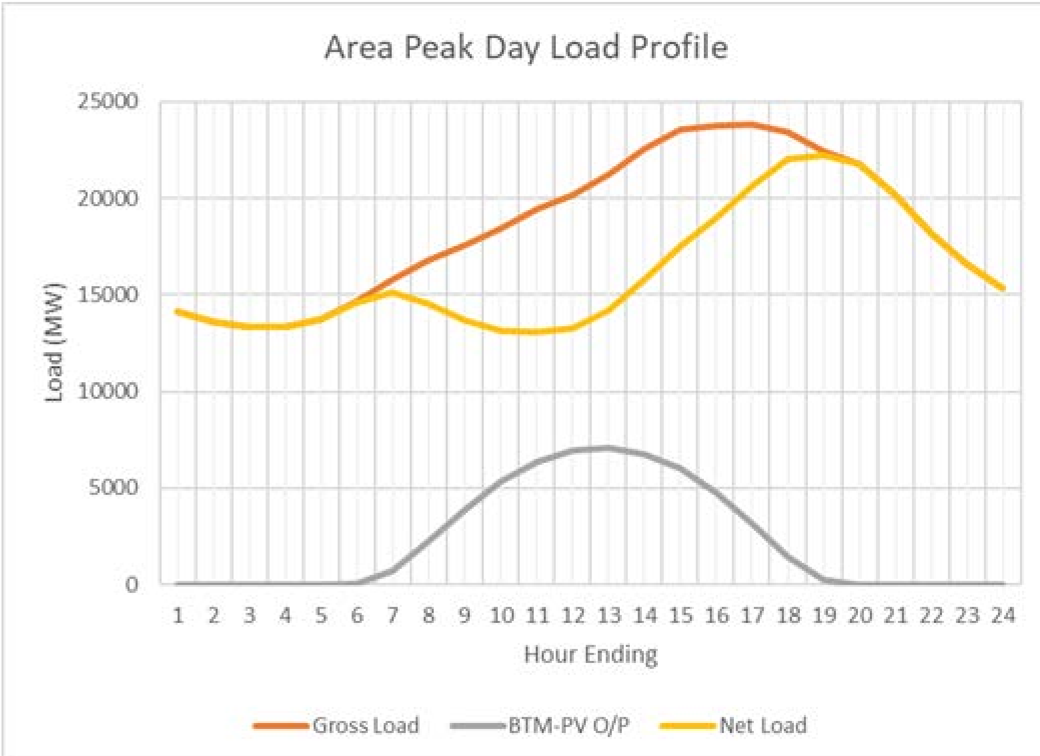
- This requirement is relevant for consideration of DER.
- The existing language does not preclude consideration of DER.
- The existing language is not clear for consideration of DER.

Supplemental Discussion

The term Load is defined in NERC Glossary of Terms as “An end-use device or customer that receives power from the electric system.” This definition is in line with the concept of “gross load” (or “gross demand”) that refers to the total amount of power consumed by end-use device or customer, without any offset by generation on the demand side. Therefore, the current language of the standard may be interpreted as requiring to study peak or off-peak gross load.

With increased penetration of DER, what the transmission system supplies is the net load (net load = gross load – DER output) as seen at the T-D interface, which might reach its peak during operating conditions that are not at the gross peak load hour. Therefore, the most stressed condition of the overall transmission system should be defined by net load rather than gross load. R2.1.1 and 2.1.2 defines reference conditions to be studied. These reference conditions should be the most stressed condition which is defined by the net load. As stated above, simply referring to “System peak Load” in the TPL-001 standard, the requirement may be interpreted as System peak gross load. This interpretation would limit the flexibility for the TP and PC to determine which reference condition is more appropriate for assessing their system. In addition, a high gross load hour may be the most stressed condition for contingencies that may trip large amounts of DER. High gross load may be added as additional sensitivity scenarios under R2.1.3.

An example is provided in the diagram below of California’s hourly profiles that illustrate differences between peak gross load and peak net load. Peak gross load occurred at 4pm at around 24,000 MW, however, due to DER output, the net load of that hour was around 20,000 MW. On the other hand, at 6 pm, although gross load was slightly lower than 4pm, due to significantly lower DER output, the net load reached peak at around 22,000 MW. The SPIDERWG recommends that the peak net load of 22,000 MW should be studies because it’s the operation condition when the transmission system is under highest loading. However, the current language in TPL-001-5 can be interpreted to require TP or PC to study the peak gross load hour at 4pm, when net load was 20000 MW.



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, the location of the load can vary between peak net load hours and peak gross load hours. In one condition the residential area could have most of the load but in another condition where the sun is up the residential load could be small. As a result, even if net load levels are similar between peak hours of gross and net system load, they 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). As there’s no existing definition of term “Generation”, it’s not clear if different DER output levels are covered under the language in R 2.1.3 “Generation additions, retirements, or other dispatch scenarios. Clarification is needed or language edits is recommended to include DER output level sensitivities.

The SPIDERWG recommends the SDT to review and edit the current language in R2.1 regarding the use of term "Load", to ensure it clearly defines most critical conditions as intended, in systems with high DER penetration. When selecting steady state reference conditions to study for Planning Assessment, the distinction between gross load and net load is quite important. The SPIDERWG recommends that the SDT should also consider whether the terms "Gross Load" and "Net Load" be added to the NERC Glossary of Terms.

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[8].

[8] 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).

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.

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 Distributed Energy Resource Modeling[9], DERs 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 case represents. To evaluate the dynamic behavior of the BPS under System peak Load and Off-Peak Load, 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[10], 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[11] 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 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 R2.2.

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.

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[9] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_DER_Modeling_Parameters_-_2017-08-18_-_FINAL.pdf

[10] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_Modeling_DER_in_Dynamic_Load_Models_-_FINAL.pdf

[11] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf

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, this 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. As DER are included in TPL-001 studies, it is important to account for changes, in response to NERC guidelines and standards and IEEE 1547, that alter their performance.

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 not 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. An implementation guideline should be developed to clarify that DER could part of CAP.

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.

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

The current language in R3 is not clear regarding whether and how to consider DER as planning events. While the current language in the R3 doesn't preclude consideration of DER, it also doesn't explicitly require inclusion of DER contingencies. Requirement R3.4 allows PC and TP to include only contingencies that are expected to produce more severe System impacts with the rationale for those Contingencies selected for evaluation shall be available as supporting information. Without changes to the Standard or further guidelines, the assessments may neglect to evaluate the impact of DER planning events (*i.e.* loss of a generator), regardless of the penetration level. Development of Contingency list should include contingency of explicitly modeled DER when they are expected to produce a more serve System impact on the BES. The DERs categorized as U-DER in the NERC Reliability Guideline for Distributed Energy Resource Modeling[12] are typically the ones that are modeled explicitly in the power flow model. The R-DER are not expected to be included in the Contingency list. If the level of penetration or U-DER size is not significant, the assessment may be able to exclude DER contingencies with rationale.

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.

SPIDERWG Review Finding

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

[12] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_DER_Modeling_Parameters_-_2017-08-18_-_FINAL.pdf

- 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 SPIDERWG, this should not considered extreme events 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 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 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. 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 this requirement applies to DERs that are located on the demand side offsetting the load. 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.

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 R3.2

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 synchronous and non-synchronous generators.

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. Contingency analysis should include aggregated DER loss as a contingency where applicable.

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. 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, if any, 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.

SPIDERWG Review Finding

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

Participants

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