NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

# Reliability Guideline

## DER Data Collection and Model Verification of Aggregate DER

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RELIABILITY | RESILIENCE | SECURITY




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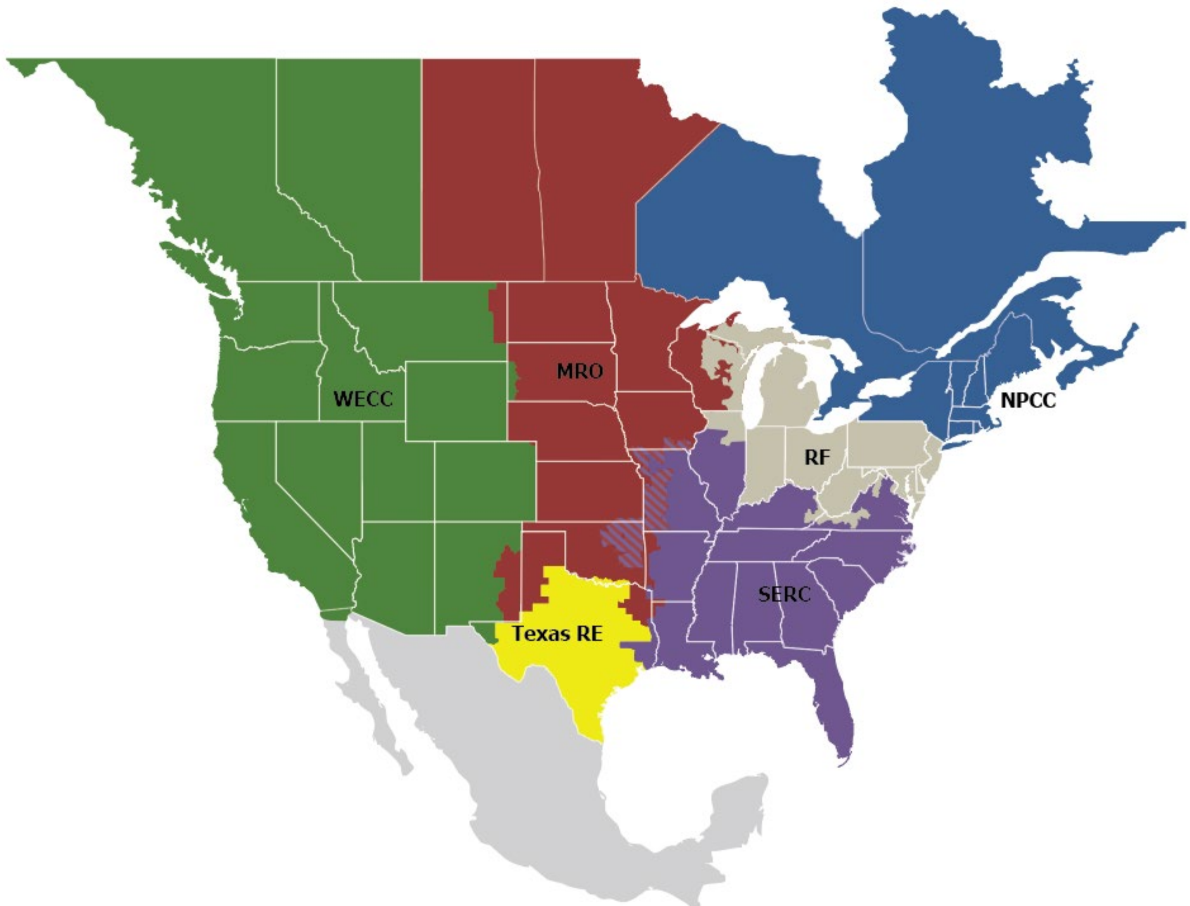
# Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the NERC and the six Regional Entities, is a highly reliable, resilient, 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 made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners /Operators participate in another.

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| **MRO** | Midwest Reliability Organization |
| **NPCC** | Northeast Power Coordinating Council |
| **RF** | ReliabilityFirst |
| **SERC** | SERC Reliability Corporation |
| **Texas RE** | Texas Reliability Entity |
| **WECC** | WECC |

# Preamble

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 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 nor are they Reliability Standards; 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.

# Executive Summary

Modeling the BPS for performing BPS reliability studies hinges on the availability of data needed to represent the various elements of the grid. While many individual BPS elements are modeled explicitly,[1] some components are represented in aggregate. These aggregate representations include end-use loads[2] as well as a growing amount of distributed energy resources (DER).[3] As the penetration of DERs continues to grow, representing DERs in planning assessments becomes increasingly important. Steady-state power flow, dynamics, short-circuit, electromagnetic transient (EMT), and other types of planning studies may need information and data that enable transmission planners (TP) and planning coordinators (PC) to develop models of aggregate amounts of DERs for planning purposes. Further, these models used to represent DER aggregations should be verified to some degree. 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 TPs and PCs to effectively perform an appropriate level of model verification to ensure that planning assessments are capturing the key impacts that DERs can have on BPS reliability.

TPs and PCs establish modeling data requirements and reporting procedures per the requirements of NERC Reliability Standard MOD-032-1.[4] The data requirements should include specifications for collecting DER data for the purposes of aggregate DER modeling, particularly as DER penetration levels continue to increase. Clear and consistent requirements developed by the TPs and PCs will help facilitate the transfer of information between the distribution providers (DP), resource planners (RP), and any other external parties (e.g., state regulatory entities or other entities performing DER forecasting to the TP and PC for modeling purposes). The modeling data requirements established by TPs and PCs may differentiate utility-scale DERs (U-DER) and retail-scale DERs (R-DER) based on their size, impact, or location on the distribution system.[5] U-DERs may require detailed information regarding the facility while smaller-scale R-DER data will typically represent aggregate amounts of DERs. Both individual and aggregate information pertaining to DER levels can be useful to TPs and PCs as they develop DER models for their footprint. The MOD-032 designees should also ensure clear and consistent internal processes for their TPs and PCs to accurately account for aggregate amounts of DERs in the Interconnection-wide planning cases. TPs and PCs should also establish clear requirements and any applicable thresholds regarding DER modeling practices; however, all DERs should be accounted for and reported to the TP and PC for modeling purposes.[6] Any TP or PC modeling thresholds established for aggregate DER modeling should be based on engineering judgment and experience from studying DER impacts on the BPS; data regarding aggregate amounts of DERs will need to be collected by TPs and PCs to facilitate these modeling threshold studies.

This guideline provides TPs and PCs with tools and techniques that can be adapted for their specific systems to verify that the created aggregate DER models 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

[1] Such as BPS transformers, generators, circuits, and other elements

[2] Typically loads are aggregated to each distribution transformer. Therefore, all loads connected to that distribution transformer are represented as one load in the steady-state base case, and then an aggregate representation of the dynamic performance of those loads is developed using engineering judgment combined with available data.

[3] For the purpose of this guideline, SPIDERWG refers to a DER as "any source of electric power located on the distribution system."

[4] https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=MOD-032-1&title=Data%20for%20Power%20System%20Modeling%20and%20Analysis&jurisdiction=United%20States

[5] U-DER and R-DER are terms used for modeling aggregate amounts of DER. Refer to the flexible framework established in previous NERC reliability guidelines: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_ModelingMerge_Responses_clean.pdf.

[6] This aligns with the guidance provided in NERC *Technical Report Distributed Energy Resource Connection Modeling and Reliability Considerations*: https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf.

utility-scale DERs as well as capturing the general behavior of the Transmission-Distribution (T-D) interface.[7] This guideline discusses when model verification is triggered as well as how to understand the mix of different DER characteristics and 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 TOs, TPs, PCs, and DPs understand the types of data needed for analyzing DER performance for verification 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.[8]

# Modeling and Verification for Future Study Conditions

TPs and PCs should see future guidance from the NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG*)* that details 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 to 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 considerations are not applicable when verifying the DER model; however, they are to be considered when performing a study with a verified DER model.

# Key Findings

During the development of this guideline, the NERC SPIDERWG identified the following key findings:

- **Model Development:** TPs and PCs require coordination and data from Transmission Owners (TOs) and DPs when developing their set of transmission models. DER model development is no exception, and with key data[9] provided to the TP and PC, the transmission entities can populate a model that represents the aggregate behavior of DER behind a T-D interface. Modeling practices will differ[10] between each TP and PC; however, all DER should be accounted for in such a way that facilitates easy identification of DER in the planning model.
- **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 high-side of the transmission–distribution (T–D) interface, most commonly the T–D transformers. For U-DERs, this may be at the point of interconnection of each U-DER.[11]
- **Aggregation of U-DER and R-DER Behavior:** Verification of aggregate DER models becomes more complex when both U-DERs and R-DERs 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 for DER modeling follow the MOD-032 practices set by TPs and PCs. These practices typically include steady-state, dynamic, and short-circuit representations. Some data requirements may include geomagnetic disturbance (GMD) or EMT specifications in specific areas. DER model verification practices should ensure that both steady-state and dynamic modeling are supported.
- **Event Selection for Model Verification:** A relatively large disturbance on the BPS (e.g., a nearby fault or other event) is the most effective means of dynamic model verification; however, these events are not necessarily the only trigger of model verification. It should be noted that aggregate model verification is not a one-time

[7] A T-D interface is a fictitious point where the transmission system ends and the distribution system ends, demarcated by one or multiple transformers at the distribution substation.

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

[9] The data here is related to the building of the aggregate representation of DER in transmission cases. TOs and DPs likely do not have all data available. All data available is not a prerequisite for sending data to develop transmission models.

[10] For example, two entities will likely differ in their practices for when to model a larger DER installation as a stand-alone generator record behind the T-D interface rather than using automated load models that lump the large DER installation as a component of the aggregate.

[11] For more discussion on placement of measurement devices, see **Chapter 1.**

exercise. Since system loads and DER output levels keep changing when more events happen and the measurement data becomes available, the verified models should be checked to ensure that other events that have happened in the system can be replicated.

- **Concept of Verified Models:** Developing an aggregate DER model is not equivalent to having a verified model.[12] A verified model should not be expected to be usable for all types of planning studies. A developed aggregate DER model for the positive sequence simulation tools is a mathematical representation at a given location while verification of this model is an exercise that entails comparing the 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. Developing a model useful for study, based on information attained through model verification, requires engineering judgement.[13]

## Key Recommendations for DER Data Collection

From the key findings previously listed, the following recommendations are intended to help guide TPs and PCs in performing aggregate DER model verification in their planning studies:

- TPs, TOs, and PCs should encourage DPs and other applicable entities that may govern DER interconnection requirements to revise interconnection requirements to ensure both high and low time-resolution data collection.[14]
- TPs, PCs, TOs, and other applicable entities that may need DER information should coordinate with DPs for facilities connected to distribution systems to determine the necessary measurement information that would be of use for DER modeling and model verification and jointly develop requirements[15] 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 newer DER models,[16] rather than the existing DER models, can be verified with additional data should a more accurate representation be required.
- TPs and PCs should review their modeling practices and determine if verification of both the load and DER components of their models should be done together or separately. Verifying both components simultaneously is recommended for enhanced efficiency and improved model accuracy.
- TPs and PCs should coordinate with their TOs, Transmission Operators (TOP), and DPs to gather measurement data to verify the general behavior of aggregate DER.[17] 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.

## Key Recommendations for DER Model Verification

With the purpose of taking a correctly parameterized aggregate DER model and tuning it to match real performance, TPs and PCs should consider the following:

[12] This is true for all sets of models and is not exclusive to aggregate DER models.
[13] 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).
[14] SPIDERWG recognizes that this recommendation may take some time depending on the group of entities to be involved due to the inclusion of distribution, which is not the case with BPS-connected resources.
[15] As the TPs, PCs, and TOs are dependent on the DP to have the data, this will likely require actions from state regulatory bodies and DPs to establish requirements to gather this information for the highest degree of success. However, actions taken on the high side of the T-D interface can improve model verification effectiveness for aggregate DER models.
[16] For example, root-mean-squared (RMS) three-phase models
[17] SPIDERWG is actively developing guidance on how this coordination should take place to ensure reliability of the BPS.

- Location of measured voltage, frequency, power, or other quantity with respect to the electrical terminals of the DER devices
- Correlation of output to end-use demand and the aggregate response of DER devices at the T-D interface[18]
- Accurate and robust metering equipment should be installed on the high or low side of the T–D transformer as well as on equipment near the large DER terminals. These measurements should be made available to the TP and PC on request and stored for a reasonable amount of time after an event triggers the recording.

With the above three bullets in mind, TPs and PCs should use measurement-based or non-measurement-based approaches for steady-state or dynamic model verification of their DER models. Like BPS device models, operational considerations and adjustments are required to perform the study conditions. To change a verified model to the study conditions, the following items should be considered:

- Time of day, month, or year[19]
- Electrical changes between verified model and study model[20]
- Study sensitivity assumptions and conditions[21]

[18] This is particularly true of BESS DERs.

[19] Irradiance and other meteorological quantities are affected by time, and some DER types are dependent upon this weather data.

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

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

# Introduction

The ability to develop accurate models for BPS reliability studies hinges on the availability of data and information needed to represent the various elements of the grid. While many individual BPS elements are modeled explicitly (e.g., transformers, large BPS generators, transmission lines), some components of the grid are represented in aggregate for the purposes of BPS studies. Such models include the representation of end-use loads[22] as well as a growing focus on the representation of aggregate amounts of DERs. TPs and PCs establish modeling data requirements for DER data for the purposes of transmission planning assessments, and reasonable representation of DERs in the models used to execute these studies will be increasingly important. As this guideline highlights, DPs likely account for the aggregate amount of DERs connected to their system with varying degrees of detail and information available. In some instances, RPs may have information pertaining to future projections of DERs.

The case for a high-quality model is further emphasized by the rapidly growing DER penetrations across North America. Such models should be "trusted" to a suitable degree to incorporate into BPS planning studies, much like how TPs and PCs currently account for aggregated load. This guideline further identifies areas where a TP's and PC's level of "trust" can be validated or verified for use in bulk system studies. Other SPIDERWG guidance materials provide TPs and PCs with recommendations for modeling aggregate amounts of DERs and their parameterization in transient dynamic studies.[23] 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. TPs and PCs gain more confidence in their aggregate DER models after verifying their accuracy and the result is increased trust in BPS planning studies.

## Purpose

The primary objective of this reliability guideline is to provide recommended practices for TPs and PCs to establish effective modeling data and model verification requirements regarding aggregate DER data for the purposes of performing reliability studies. This includes TPs and PCs working with DPs, RPs, and other applicable data reporting entities to facilitate the transfer of data needed to represent aggregate DER in BPS reliability studies. TPs and PCs should review their requirements and consider incorporating the recommendations presented in this guideline into those requirements. DPs are encouraged to review the recommendations and reference materials to better understand the types of modeling data needed by the TP and PC and to help facilitate this data and information transfer. In many cases, the aggregate data needed for modeling purposes may not require detailed information from individual DERs; rather, aggregate data related to location, type of DERs, vintage of IEEE 1547, interconnection time line and projections, and other key data points can help develop aggregate DER models. The detailed guidance provided in this guideline follows the required data transfer established in NERC Reliability Standard MOD-032-1 and speaks to the system level verification in MOD-033.

## Applicability

This reliability guideline is applicable to TPs, PCs, TOs, and other users of DER modeling for representing aggregate DER in their set of models as well as those entities performing model verification or validation checks for the same models.

[22] Typically loads are aggregated to each distribution transformer. Therefore, all loads connected to that distribution transformer are represented as one load in the steady-state base case, and then an aggregate representation of the dynamic performance of those loads are developed using engineering judgment combined with available data.

[23] SPIDERWG has published a guideline on the modeling and parameterization of aggregate DER models here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_ModelingMerge_Responses_clean.pdf.

## Related Standards

The topics covered in this guideline are intended as useful guidance and reference materials as TPs and PCs create and verify DER models in studies. While this guidance does not provide compliance guidance of any sort, the concepts apply generally to the following standards:

- MOD-032
- MOD-033
- TPL-001
- PRC-002

# Background

The NERC *Reliability Guideline: Modeling DER in Dynamic Load Models*, published December 2016, established a foundation for classifying DERs as either U-DERs or R-DERs for the purpose of modeling. That guideline also provided a flexible framework for modeling U-DERs and R-DERs in steady-state power flow base cases as well as options for modeling DER in the dynamic models. This included options for representing DERs with a stand-alone DER dynamic model or integrating DERs as part of the composite load model. The NERC *Reliability Guideline: Distributed Energy Resource Modeling*, published September 2017, provided further guidance on establishing reasonable parameter values for DER dynamic models. That guideline reviewed the available dynamic models and recommended default parameter values that could be used as a starting point for modeling DERs. The NERC *Reliability Guideline: Parameterization of the DER_A Model* recommended use of the DER_A dynamic model to represent either U-DERs or R-DERs in dynamic simulations. This model was in the process of being developed during the publication of the previous two guidelines. Therefore, that guideline demonstrated the benchmarking and testing of the DER_A model and also provided recommended default parameter values for the DER_A model for different scenarios of DER installations in various systems. Again, the recommendations presented in that guideline are intended to be a starting point for planning engineers to further determine representative DER dynamic model parameter values. In 2021, the NERC RSTC initiated a review of all approved reliability guidelines, and the content in the above three documents is now housed completely in a new reliability guideline titled *Reliability Guideline: Parameterization of the DER_A Model for Aggregate DER.*[24]

The NERC Distributed Energy Resources Task Force (DERTF) also published a technical report on *Distributed Energy Resources: Connection Modeling and Reliability Considerations,*[25] published December 2016, and a technical brief on *Data Collection Recommendations for Distributed Energy Resources,* published March 2018.[26] Both of these reports provided industry with a high-level overview of the information that may need to be collected and shared among entities for the purposes of modeling and studying DER impacts as well as monitoring DERs in real-time. Furthermore, these reports emphasized that netting of DERs with load should be avoided since it can mask the impacts that either may have on BPS reliability, particularly for dynamic simulations.

The NERC SPIDERWG has developed this reliability guideline to build upon past efforts and specifically focus on gathering the data and modeling information needed to effectively execute transmission planning modeling and study activities. Effectively gathering data regarding the aggregate levels of DERs is critical for TPs and PCs to execute planning assessments and ensure reliable operation of the BPS in the long-term planning horizon.

[24] This document merges all content of the previous, now unavailable documents. The merged document is available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_ModelingMerge_Responses_clean.pdf.
[25] https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf
[26] https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/DER_Data_Collection_Tech_Brief_03292018_Final.pdf

## Recommended DER Modeling Framework

The recommendations regarding DER data collection for the purposes of modeling and transmission planning studies use the recommended DER modeling framework proposed in previous NERC reliability guidelines (see **Figure I.1**). For purposes of modeling, the framework characterizes DERs as either U-DERs or R-DERs. These definitions are intended to be adapted to specific TP and PC planning practices and specific DER installations as needed. As a reference from previous DER modeling recommendations, these definitions include the following:

- **U-DER:** DERs directly connected to, or closely connected to, the distribution bus or connected to the distribution bus through a dedicated, non-load serving feeder.[27] These resources are typically three-phase interconnections and can range in capacity (e.g., 0.5 to 20 MW).
- **R-DER:** DERs that offset customer load, including residential,[28] commercial, and industrial customers. Typically, the residential units are single-phase while the commercial and industrial units can be single- or three-phase facilities.

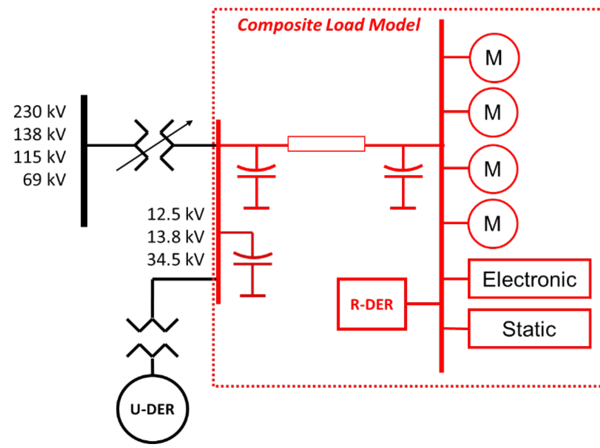


**Figure I.1: DER Modeling Framework**

Both U-DERs and R-DERs can be differentiated and modeled in power flow base cases and dynamic simulations. TPs and PCs have successfully adapted these general definitions for their systems and often refer to U-DERs and R-DERs for the purposes of modeling aggregate DERs. Aggregate amounts of all DERs should be accounted for in either U-DER or R-DER models in the base case, and TPs and PCs may establish requirements for modeling any U-DERs as well as aggregate amounts of the remaining DERs as R-DERs. The aggregate impact of DERs, such as the sudden loss of a large amount of DERs, has been observed[29] to be a contributor to BPS performance during disturbances.

There will inherently be lag between the time when DER steady-state and dynamic models are created and when verification of these models with 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 DER behaviors. Explicit modeling of aggregate DER amounts is strongly recommended[30] versus netting these resources with load as the key functional behaviors are different.

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[27] Some entities have chosen to model larger (i.e., multi-MW) U-DERs that are connected further down on load-serving feeders as U-DERs explicitly in the base case. This has been demonstrated as an effective means of representing U-DERs and is a reasonable adaptation of the above definition. TPs and PCs should use engineering judgment to determine the most effective modeling approach.

[28] This also applies to community DERs that do not serve any load directly but are interconnected directly to a single-phase or three-phase distribution load-serving feeder.

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

[30] https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf

## Types of Reliability Studies

Data of BPS elements as well as other necessary aspects[31] of the interconnected BPS are used in a wide array of reliability studies performed by TPs and PCs. Studies considered by SPIDERWG include the following:

- **Steady-State Studies:[32]** Steady-state reliability studies include both power flow analysis and steady-state contingency analysis of future operating conditions.[33] In addition, steady-state stability studies typically include voltage stability[34] as well as small signal eigenvalue analysis. These studies all require information regarding the end-use load as well as the DER penetration to accurately model the behavior of these resources in future normal and abnormal operating conditions.
- **Dynamic Studies:[35]** Dynamic studies typically refer to phasor-based, time-domain simulations of the interconnected BPS. These studies include performing contingencies and identifying any potential instabilities, uncontrolled separation, or cascading events that may occur due to BPS dynamic behavior and when considering all the elements connected to the BPS. The data used in these simulations also represents the aggregate[36] effects of end-use loads as well as aggregate DERs. DERs, particularly in dynamic simulations, can have a relatively significant impact on BPS performance for voltage stability due to redispatched dynamic reactive devices on the BPS, rotor angle stability due to changes in BPS-connected generation dispatch, and frequency stability due to changes in rate of change of frequency and frequency response performance.[37] Furthermore, the dynamic behavior (e.g., momentary cessation, tripping, voltage and frequency support) of aggregate amounts of DERs can have a significant impact on the BPS, and the expected performance of aggregate DERs should be represented in dynamic models.[38] In many cases, the details of individual DERs are not relevant unless their individual size is deemed impactful[39] to BPS performance. A reasonable understanding of the aggregate behavior of DERs is more suitable for most dynamic simulations.[40] Regardless, TPs and PCs need access to DER data to determine potential impacts of aggregate amounts of DER on the BPS.
- **Short-Circuit Studies:** Short-circuit studies are used for a wide range of analyses, such as assessing breaker duty and setting protective relays. As DERs continue to offset BPS-connected generation, particularly during high DER output levels, short-circuit conditions may need to be assessed more regularly, or close attention may be needed in certain areas of low short-circuit strength. This is particularly a concern for systems with high penetrations of DERs as well as BPS-connected inverter-based resources. As described in **Chapter 4:**, some DER data related to short-circuit performance may be needed as DER penetrations increase. It is important for TOs and TPs to establish data collection practices early to help ensure sufficient data is available for modeling purposes. TOs, TPs, and PCs will need to determine an appropriate time to begin modeling DERs for short-circuit studies; however, gathering the necessary data will help facilitate improved modeling practices in the future.

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[31] Such as aggregate demand (steady state) and the dynamic nature of end-use loads (dynamics)
[32] Fundamental-frequency, positive sequence, phasor simulations
[33] For example, high penetrations of DERs may have an impact on BPS voltage control and voltage stability due to reduced or limited dynamic reactive resources on the BPS.
[34] Active power-voltage (P-V) and reactive power-voltage (Q-V) analysis
[35] Fundamental-frequency, positive sequence, phasor simulations
[36] Or possible individual large loads or resources connected to the distribution system if they potentially impact the BPS
[37] NERC SPIDERWG is working on more comprehensive reliability guidelines that will cover these topics in more detail, e.g., impacts of DERs to underfrequency load shedding (UFLS) programs.
[38] https://www.ofgem.gov.uk/publications-and-updates/ofgem-has-published-national-grid-electricity-system-operator-s-technical-report
[39] Again, this is based on TP and PC engineering judgment and experience studying DER impacts. For TPs and PCs to execute these studies, they will likely need to gather relevant data to create aggregate or large individual DER models.
[40] This is for at least most instances of R-DER. U-DER may need additional or more accurate data collection in some cases.

- **Geomagnetic Disturbance (GMD) Studies:** GMD studies are performed for applicable facilities per NERC TPL-007-3,[41] which analyzes the risk to BPS reliability that could be caused by quasi-dc geomagnetically induced currents (GIC) that result in transformer hot-spot heating or damage, loss of reactive power sources, increased reactive power demand, and misoperation of system elements due to GMD events. TPL-007-3 GIC vulnerability assessments typically do not model the distribution system for various reasons because the transmission-distribution (T-D) transformers include a delta-wye transformation with GICs not propagating through delta windings and distribution circuits being relatively short in length with high impedance. Therefore, GICs on the distribution system are minimal and are not likely to impact the distribution system. Based on this finding, DER modeling for the purposes of GMD vulnerability assessments per NERC TPL-007-3 is likely not needed at this time.[42]
- **EMT Studies:** Given the higher fidelity models, EMT analysis for DER interconnections can be useful in finding low short-circuit strength issues, such as controls instabilities, voltage control coordination issues, inability to ride through BPS disturbances, and also in benchmarking positive sequence fundamental-frequency phasor models. Items such as ride-through and voltage response can be better represented in EMT studies than in traditional positive sequence studies. This is important when large groups of DERs (relative to the size of the system) are interconnected. Most industry experience to-date is based on studies conducted of BPS-connected inverter-based resources. However, EMT studies may be useful when large[43] amounts of aggregate DERs are connecting to areas where system strength is of concern. More industry research and experience is needed in this area; however, EMT studies are increasingly used to ensure reliable operation of the BPS and should be considered in the context of increasing DER penetrations.

For all types of reliability studies, each TP and PC will need to determine the relative impact to the BPS as DER penetrations increase. To determine such impacts, information is needed to be able to model aggregate amounts of DERs. Therefore, this guideline stresses the importance of TOs, TPs, and PCs establishing data collection requirements (per the latest effective version of MOD-032) that are specifically related to collecting aggregate DER data sufficiently early such that the data is available for modeling purposes either now or in the future.

## Case Assumptions

Similar to end-use load models, the assumptions used for modeling DERs will dictate how the resource(s) should be represented in planning base cases. NERC TPL-001-4 requires that planning assessments use steady-state, stability, and short-circuit studies to determine whether the BES meets performance requirements for system peak and off-peak conditions. TPs and PCs need to determine and specify these conditions to ensure clarity in data submittals from DPs and RPs in conjunction with other applicable data sources. MOD-032 designees that create the Interconnection-wide power flow and dynamics base cases should also ensure that clear and consistent modeling requirements are developed for TPs and PCs to reasonably account for and model aggregate DERs in the planning cases. For example, solar photovoltaic (PV) DERs are highly dependent on the time of day in developing assumptions used to create the base cases. TPs and PCs will need to consider the coincidence of DER output with demand levels to ensure cases are set up appropriately. In some areas, system peak loading may occur during late afternoon when active power output from solar PV is minimal (as illustrated in **Figure I.2** and discussed below); however, light loading conditions may occur when DER output is near its maximum. Regardless, setting up DER levels in planning studies hinges on sufficient data being collected by the TP and PC regarding the aggregate levels and behavior of DERs in their footprint.

[41] https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-007-2.pdf

[42] Note that GICs on the BPS can create high levels of harmonic voltage distortion that can propagate to the distribution system. Situations where harmonic voltage distortion is identified may warrant closer investigation by affected entities.

[43] The term "large" is relative to each specific system and will need to be considered by each TP and PC. However, to execute these types of studies some degree of data will need to be collected by TPs and PCs.

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

- **Year:** Each base case represents a specific year being studied. TPs are responsible for creating base cases of future, expected system conditions in the long-term planning horizon that include forecasted demand levels and should also include forecasted aggregate amount of DERs for each year being modeled. This data is based on local or regional DER growth trends and can come from multiple data sources.[44]
- **Season:** Each base case typically has a specified season (e.g., summer, fall, winter, spring) or type of season (e.g., shoulder season), which is already defined in the planning process.
- **Time of Day:** Each TP and PC should identify the critical times of day that should be studied; this is often dependent on the time when gross demand peaks (or hits its minimum), when aggregate DER output peaks, and when net demand peaks (or hits its minimum). The assumed hour of day for each base case should be clearly defined by TPs and PCs to facilitate data collection from DPs and base case creation.
- **Load (Peak vs. Off-Peak):** The NERC TPL-001 standard uses terms such as “System Peak Load” and “System Off-Peak Load”; however, it is not clear if these terms refer to gross or net load (demand) conditions. Therefore, it is recommended that TPs and PCs clearly articulate which load is being referred to in the case creation process. As the penetration of DERs continues to grow, it is likely that both peak and off-peak gross load and net load conditions should both be studied for potential reliability issues. This is particularly applicable to systems where the gross load and net load peak and off-peak conditions are significantly different. In all cases, TPs and PCs should ensure that gross load data is explicitly provided such that net loading can effectively be simulated by DER dispatch.
- **DER Dispatch Assumptions:** The TP and PC likely have established assumptions around how the DER will be dispatched in the planning base cases. While this may not directly affect the information flow from the DP to the TP and PC, these assumptions may help the DP in gathering the necessary data and information. These dispatch assumptions may include both active power output levels and reactive power capability. Additional planning base cases should reflect expected stressed system conditions that depend on the geospatial and temporal patterns (e.g., weather patterns) of demand and DERs, and their impact on BPS-connected generation dispatch. These conditions might include heavy transmission flows that have a very different pattern than during peak-load conditions.

[44] Such as state incentive policy forecasts or other relevant regional DER forecasting tools

To illustrate this concept, consider an example of the development of the Interconnection-wide "System Peak" base case. The TP in this example assumes that the "System Peak" case represents the hour of peak net demand (i.e., gross demand less DER output). Refer to Figure I.2 for a visualization of this example. Assume that this is a summer peak case, so the season has been defined. The gross demand peaks around 4:00 p.m., and net demand peaks around 5:00 p.m. local time, respectively, defining the time of day. Based on this, DER output assumptions are established. DERs in this area are predominantly distributed solar PV, and output is assumed to be roughly 50–60% of its maximum capability at 4:00 p.m. and much closer to 0% of its maximum capability at 6:00 p.m. Assume in this example that DERs are compliant with IEEE Standard 1547-2003 based on time of installation of the DERs.[45] Furthermore, assume the DP has not required volt-var functionality by DERs, so the DERs are not expected to provide voltage support; rather, they are assumed to operate at unity power factor (defining active and reactive power output assumptions to be modeled). This concept applies to off-peak loading conditions as well as system peaking in winter.

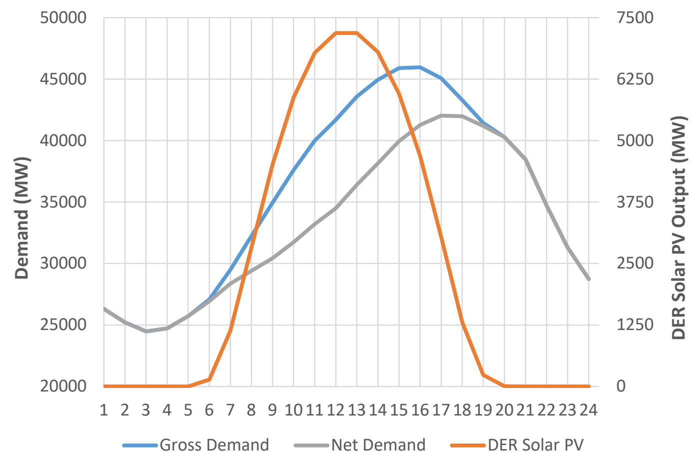


**Figure I.2: DER and Demand Profiles for Summer Peak Condition [Source: CAISO]**

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

### Considerations for Distributed Energy Storage

Recent discussions regarding the expected growth of energy storage, particularly battery energy storage systems (BESS), relate to both BPS-connected and distribution-connected resources. Many of the recommendations regarding data collection and model verification of aggregate DERs also apply to distribution-connected BESS. Throughout this guideline, more detail is provided where there are distinctions for distribution-connected BESS. However, SPIDERWG has found that aggregate modeling of distributed storage relates more to case dispatch assumptions than building of a transmission planning model.

## Time Line and Projections of DER Interconnections

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

[45] https://standards.ieee.org/standard/1547-2003.html

Visualization of DER penetration, both existing and forecasted values, can be useful to the TP for modeling DER in steady-state power flow base cases as well as dynamic simulations. **Chapter 2** and **Chapter 3** describe why understanding and estimating the vintage and deployed settings of DERs installed can be of significant value for the purposes of DER modeling.[46]

## Example of Applying DER Interconnection Time Lines

This section provides an illustrative example of applying DER interconnection times; it is intended solely as an example that could be adapted by TPs and PCs and is not intended to establish expected dates of standards implementation. **Figure I.3** shows an example system with installed DER capacity from early 2010 to the end of 2019 as illustrated by the solid blue curve. The TP and PC are in the process of developing a five-year out 2025 base case, and they have pulled in forecasted DER growth (dotted blue curve) from either the RP, DP, or other external source (e.g., state-level agency or regulator body) that projects DER out to the end of 2025.

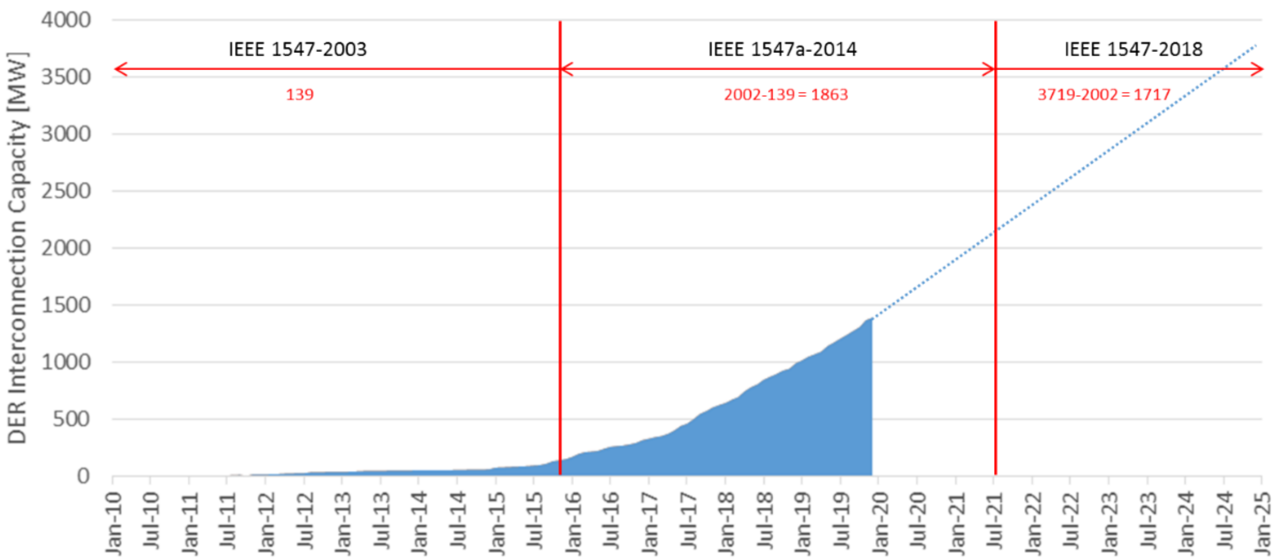


**Figure I.3: Example DER Interconnection Capacity Growth**

Assume all DERs connected to this example system are inverter-based and that the DERs comply with the various versions of IEEE 1547. For example, up to November 2015, due to interconnection requirements at the time, assume DERs were installed with settings compliant with IEEE 1547-2003. After November 2015 up to an assumed July 2021, assume[47] that DERs were installed with settings compliant with IEEE 1547a-2014.[48] Finally, after July 2021, assume that DERs will be installed with settings compliant with IEEE 1547-2018[49] once interconnection requirements are updated and compliant equipment becomes available. The red numbers show the amount of aggregate DER capacity that meets each standard implementation. It is clear that a small number of resources are compliant with IEEE 1547-2003 while the remaining majority are mixed between IEEE 1547a-2014 and IEEE 1547-2018. The revised IEEE 1547-2018 includes much more robust ride-through performance and the capability for active power-frequency control on overfrequency conditions. In this example, no resources are required to maintain headroom to respond to

[46] The Electric Power Research Institute (EPRI) is launching a public, web-based DER Performance Capability and Functional Settings Database: https://dersettings.epri.com.
[47] This is an assumption used here for illustrative purposes. However, while IEEE 1547a-2014 widened the ride-through settings, actual installed settings may not have been modified unless relevant interconnection requirements were adopted by DPs.
[48] https://standards.ieee.org/standard/1547a-2014.html
[49] https://standards.ieee.org/standard/1547-2018.html

underfrequency conditions. Interconnection requirements at the time of initial publication[50] were set in 2021 to require local DER voltage control capability (volt-var capability). However, application of volt-var functionality is subject to DP practices and requirement, so wide-area implementation of this functionality should not be assumed unless confirmed as an established practice by the relevant DPs. Moreover, DP practices and adoption of 1547-2018 may supersede the wide area adoption, and TPs are encouraged to identify the relevant DP established practices for DER ride-through and operational control modes.

Based on the estimation of DER vintages as well as estimated deployed settings, the TP and PC can make reasonable assumptions regarding the following modeling considerations:

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

The ability of TPs and PCs to understand when DERs were installed will greatly improve their ability to use engineering judgment to assume modeling parameters, to then be confirmed by relevant DP practices. This is particularly important for modeling aggregate amounts of R-DERs where minimal information is available. After building a representative model for DER, a planner can, typically at a later time, verify the model against recordings from the equipment or validate the parameters with as-built information.

## 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 is intended to comprehensively review the disturbance and to identify the root cause of the event. The data needed to execute event analysis typically includes a vast array of event logs, dynamic disturbance recordings, pre-contingency operating conditions, and other forms of documentation. The pre-contingency system operating condition and the dynamic disturbance recordings captured during these events can be used for steady-state and dynamic model verification and not just for use in event analysis. Model verification’s purpose is to add fidelity to models, which this document covers. 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 that an adequate model be developed and then for an entity to gather event data to match model performance with that information. Verification of the models used in planning studies occurs when TPs and PCs use supplemental information to validate parameters in the transmission model used 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[51] to the TP/PC to validate their set of representative models of those devices. The process continues with the PC perturbing its model and storing the outputs.[52] Those model outputs and the

[50] Such requirements were added and this example left unchanged to illustrate the process of applying widespread adoption of 1547-2018 and the resulting DP practice confirmation needed.
[51] Generally, this is done by RCs, TOPs, and TOs; however, this can also be done by DPs to monitor equipment on their system.
[52] Practices may change related to software changes, similar to the current load model verification practices. SPIDERWG is reviewing and recommending simulation practice changes regarding DERs in other work products.

measured outputs are compared, and the verification procedure stops if there is a sufficient match based on the TP/PC procedures. 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 that incorporate aggregate DER would take more than one of these perturbations. An example of model verification can be found in **Appendix E** , which details an example that uses playback models to verify a set of DER models. As some of the Interconnection-wide base cases predict a future condition for resources not yet built, measurement data and forecasted conditions are not available.[53] While high-fidelity models are expected to be in these cases, many of the practices contained here are not practical. In brief, it is not practical to exhaustively verify a future model's behaviors; however, it is highly important that near-term cases have verified, high-fidelity models.

## Three Phase versus Positive Sequence Model Verification

The majority of planning studies performed by TPs and PCs use RMS[54] fundamental-frequency, positive sequence simulation tools.[55] Hence, steady-state powerflow and dynamic simulations assume[56] a balanced three-phase network that 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 simulation methods, such as a three-phase RMS dynamic simulation, an EMT, or a co-simulation; these methods require more detailed modeling data and verification activities. However, DER model verification using these 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.

[53] SPIDERWG is developing separate guidance to verify aspects of these base cases.

[54] Root-mean-square

[55] 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.

[56] This assumption is inherently built into the power flow and dynamic solutions used by the simulation tools.

# Chapter 1: Data Collection for DER Modeling and Verification

The data and information needed to create a steady-state and dynamic model for individual or aggregate DERs is different from the data and information used to verify those models. TOs, TPs, and PCs should work with their DPs and other applicable entities to collect information pertaining to existing DERs and to forecast future DER levels for planning studies of expected future operating conditions. In contrast, 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. Data collection requirements and reporting procedures established by each TP and PC are expected to vary slightly based on the types of studies being performed. However, a common set of information is needed to model DERs and common ways that data can be collected. This chapter addresses that along with placement of recording devices, gathering of measurement quantities for model verification, and the data and information used to verify the DER model(s) created.

## MOD-032-1 Data Collection and DER

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

- Requirement R1 of MOD-032-1 requires that each PC and each of its TPs jointly develop data requirements and reporting procedures for steady-state, dynamics, and short-circuit modeling data collection:
  - These requirements should include the data listed in Attachment 1 of MOD-032-1 as well as any additional data deemed necessary for the purposes of modeling.
  - The data requirements should address data format,[57] level of detail, assumptions needed for the various types of planning cases or scenarios, a data submittal time line, and posting the data requirements and reporting procedures.
- Requirement R2 of MOD-032-1 requires each of the applicable entities[58] to provide the modeling data to the TPs and PCs according to the requirements specified.
- Requirement R3 requires each of the applicable entities to provide either updated data or an explanation with a technical basis for maintaining the current data if a written notification is provided to them by the PC or TP with technical concerns regarding the data submitted.

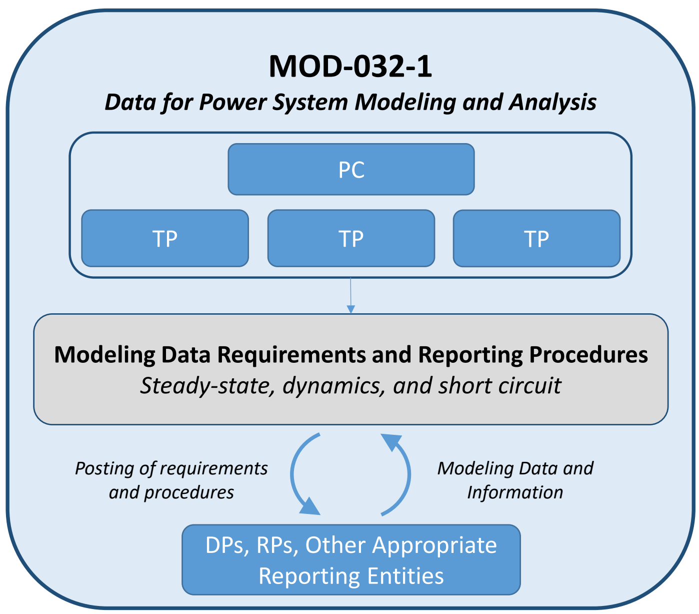


**Figure 1.1: MOD-032-1 Flowchart for DER Data**

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

[58] These include each balancing authority (BA), generator owner (GO), RP, TO, and transmission service provider (TSP). Note that, at the time of writing this guideline, the load-serving entity has been deregistered, and SPIDERWG recommends that DPs are the best suited to provide DER information to TPs and PCs for modeling purposes. Therefore, DP is used as the applicable entity throughout this document. Project 2022-

- Requirement R4 requires each PC to make the models for its footprint available to the ERO or its designee[59] to support the creation of Interconnection-wide base cases.

Attachment 1 of MOD-032-1 "indicates information that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon…A [PC] may specify additional information that includes specific information required for each item in the table below." **Figure 1.2** shows an excerpt from the MOD-032-1 Attachment 1 table.

| **steady-state**<br>*(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)* | **dynamics**<br>*(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)* | **short circuit** |
|---|---|---|
| 1. Each bus [TO]<br>a. nominal voltage<br>b. area, zone and owner<br>2. Aggregate Demand[2] [LSE]<br>a. real and reactive power*<br>b. in-service status*<br>3. Generating Units[3] [GO, RP (for future planned resources only)]<br>a. real power capabilities - gross maximum and minimum values<br>b. reactive power capabilities - maximum and minimum values at | 1. Generator [GO, RP (for future planned resources only)]<br>2. Excitation System [GO, RP(for future planned resources only)]<br>3. Governor [GO, RP(for future planned resources only)]<br>4. Power System Stabilizer [GO, RP(for future planned resources only)]<br>5. Demand [LSE] | 1. Provide for all applicable elements in column "steady-state" [GO, RP, TO]<br>a. Positive Sequence Data<br>b. Negative Sequence Data<br>c. Zero Sequence Data<br>2. Mutual Line Impedance Data [TO]<br>3. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling |

**Figure 1.2: Excerpt of MOD-032-1 Attachment 1 Table**

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

Currently, the table in Attachment 1 of MOD-032-1 does not provide a line item for aggregate DER data. Rather, the table includes a statement[60] in each of the columns that states "other information requested by the [PC] or [TP] necessary for modeling purposes" should be collected. This item should be used by the TPs and PCs as technical justification for collecting aggregate DER data necessary for modeling purposes as an interim solution until revisions to MOD-032-1 can occur. DPs should work with their respective TPs and PCs to understand expectations for gathering available DER data and making reasonable assumptions for any data that may not be available. TPs and PCs should also develop necessary processes for aggregating DER data and performing some degree of verification of the data received.[61]

Regardless of the elements explicitly defined in MOD-032-1 Attachment 1, each TP and PC should jointly develop data requirements and reporting procedures for the purpose of developing the Interconnection-wide base cases used for transmission planning assessments. These requirements are often very detailed and specific to each PC and TP planning practices, tools, and study techniques. Therefore, TPs and PCs should update their data reporting requirements for Requirement R1 of MOD-032-1 to explicitly describe the requirements for aggregate DER data in a manner that is clear and consistent with their modeling practices. Coordination with their DPs in developing these

02 is currently altering MOD-032-1 to adjust Attachment 1. Among the adjustments is the transfer of the load -serving entity to distribution provider for Item #2. These proposed edits are currently not approved and as such are not reflected in this document. See Project 2022-02 web page for latest documents here: https://www.nerc.com/pa/Stand/Pages/Project2022-02ModificationstoTPL-001-5-1andMOD-032-1.aspx.

[59] In each Interconnection within the NERC footprint, a "MOD-032 Designee" has been designated to create Interconnection-wide base cases. Each designee has a signed agreement with NERC to develop base cases of sufficient data quality, fidelity, and time lines for industry to perform its planning assessments.

[60] Refer to items #9 and #10 in the steady-state and dynamics columns in NERC MOD-032-1, respectively.

[61] NERC SPIDERWG is working on a separate reliability guideline to support the industry in performing verification of DER data and creating DER models.

requirements should result in the most effective outcome for gathering DER information for modeling.[62] **Chapter 2** provides a foundation and starting point for establishing the specific information that should be gathered for modeling purposes in coordination with the DP.

## 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[63] to provide data and information pertaining to DERs within their footprint since DPs conduct their interconnection processes for resources that interconnect to their system and may have access to the measurements necessary to perform DER model verification. Applicable entities that may govern DER interconnection requirements (e.g., states) 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[64] or other distribution entity that is not a functional NERC entity. TPs, PCs, and TOs are encouraged to coordinate with DPs and respective DER developers, generators, owners, or other distribution entities related to DERs to develop a mutual understanding of the types of data needed for 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.

DPs, TPs, PCs, and TOs should understand the types of data needed to verify DER models and to provide recommended practices for gathering this data and applying it for verification purposes. It is intended that the best "source" of this data will become apparent with clear coordination on the needs for the data. DER model verification starts with applicable entities having suitable DER modeling data available 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 exist and 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 DER interconnections. IEEE 1547 was first published in 2003 and later updated in 2018 to address the proliferation of DER interconnections. Both IEEE 1547-2003[65] and IEEE 1547-2018[66] standards are technology neutral. The monitoring requirements for both standards are presented here:

- **IEEE 1547-2003:** The IEEE 1547-2003 standard is applicable for DER installations installed prior to the full adoption and implementation of IEEE 1547-2018,[67] including provisions for DERs with a single unit above 250

[62] EPRI (2019): *Transmission and Distribution Operations and Planning Coordination*. TSO/DSO and Tx/Dx Planning Interaction, Processes, and Data Exchange. 3002016712. Electric Power Research Institute (EPRI). Palo Alto, CA: https://www.epri.com/#/pages/product/000000003002016712/.

[63] There are instances where a DP registration does not exist on the other side of the T-D interface. In these settings, there is no NERC standard requirement to obligate the distribution provider or planner to provide data. It falls then to the TO to initiate and gather the DER information in a collaborative process among these unregistered entities using best available practices. That said, the distribution planner or provider, regardless of NERC registration status, is the most suited entity to provide information due to their ability to set interconnection requirements on their system.

[64] A DER developer is an entity that procures, sites, installs, and manages the construction of a DER.

[65] https://standards.ieee.org/standard/1547-2003.html

[66] https://standards.ieee.org/standard/1547-2018.html

[67] DERs compliant with IEEE 1547-2018 had wide commercial availability beginning in 2021 based on the progress and approval of IEEE 1547.1: http://grouper.ieee.org/groups/scc21/1547.1/1547.1_index.html.

kVA or more than 250 kVA aggregated at a single point of common coupling. The 2003 version includes provisions for 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 involved in 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); 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 applicable DP for 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 point of common coupling, assuming that the needed portions of the distribution system are represented within the transmission system model. 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

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 be monitored, event-driven capture of high-resolution voltage and current waveforms also are useful for DER dynamic model verification. These allow the key 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.

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

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

An example of a recording device is a power quality (PQ) meter, 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 and during system events. These types of measurement devices record both RMS and sinusoidal waveforms at many different sample rates and are International Electrotechnical Commission (IEC) code compliant on their RMS and sinusoidal samplings. These types of meters are viable when capturing aggregate DER performance 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 and the DP regarding recording devices so that these recording devices accomplish each entity's objectives. Entities are encouraged to begin by selecting PQ meters to start this collaboration and to determine the full equipment needed for steady-state or transient dynamic data capture. The improved model quality and fidelity will benefit all stakeholders.

## 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. TPs, PCs, and DPs should consider the following recommendations 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 the T–D interface.[68] This may be acquired by measurements at the distribution substation for each T–D transformer bank or along a different distribution-connected location.[69]
- **U-DER:** U-DER models represent a single or group of DERs, so the measurements needed to verify this dynamic model must be placed at a location where the response of the U-DERs or group of DERs can be differentiated from other DERs and load response. For U-DERs 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 with engineering judgment. Applicable entities that may govern DER interconnection requirements should consider establishing capacity thresholds (e.g., 250 kVA in IEEE 1547-2003) in which U-DERs should have monitoring equipment at their point of connection[70] 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 interface are recommended in all cases, and additional measurements for capturing and differentiating U-DERs may also be warranted.

**Key Takeaway:**
Measurement locations of DER performance depend on the type of DER model (U-DERs vs. R-DERs) 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.

As described, the DER type and how it is modeled will dictate the placement of measurement devices for verifying DER models. **Figure 1.3** 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 American National Standards Institute (ANSI) acceptable continuous service voltage. These parameters represent the aggregated impact of individual feeders, as indicated by the dashed box in **Figure 1.3**. Each of the highlighted points in **Figure 1.3** 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-DERs, it is suggested that monitoring devices are placed at their terminal as

[68] Note that such a measurement, expectedly, could include the combined response from the load and the 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.
[69] 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.
[70] This point is chosen to provide information on the plant's response. It is anticipated that this will measure the flows across the transformer that connects the DER facility to the DP's system.

shown in **Figure 1.3**. While other locations are highlighted, they are not necessary for performing model verification when the two previously mentioned locations are available; however, they may be able to replace or supplement the data and have value when performing model verification.

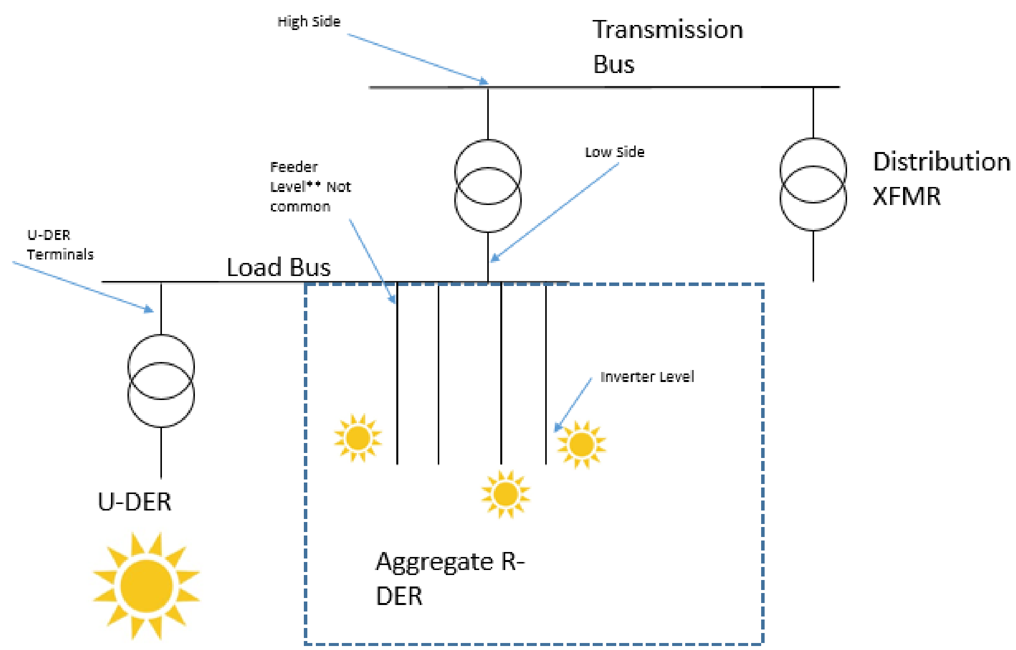


**Figure 1.3: Illustration of Measurement Locations for DER Model Verification**

## Measurement Quantities used for DER Model Verification

Measurement devices used for DER steady-state model verification for both U-DERs and R-DERs should be capable of collecting the following bolded data at their nominal frequency, and should make available, if possible, the non-bolded data:

- **Steady-state RMS voltage (Vrms)**
- **Steady-state RMS current (Irms)**
- **Active power (W)**
- Reactive power (Vars)

Measurement devices used for DER dynamic model verification for both U-DERs and R-DERs should be capable of collecting the following bolded data, and should make available, if possible, the non-bolded data:

- **RMS[71] voltage and current (Vrms, Irms)**
- **Frequency (Hz)**
- **Active power (W)**
- **Reactive power (Vars)**
- Harmonics[72]
- Protection Element Status
- Inverter Fault Code[73]

[71] References to RMS here are fundamental-frequency RMS.

[72] 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 (e.g., IEEE std. 519) and such standards refer to the upper harmonic boundary for measurement.

[73] Inverter fault code for individual R-DER is not practical to obtain in comparison to other recommendations to improve model quality. However, the aggregate or most prominent fault code for DER (both R-DER and U-DER) is beneficial when performing wide-area system validation after large disturbances. It may be more practical to infer the Inverter Fault Code of modeled R-DER from the U-DER nearby, if the Inverter Fault Code is available.

In addition to the measurements described above, DER monitoring equipment systems[74] should be able to calculate or report the following quantities:

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

**Table 1.1** provides a summary of useful locations for steady-state and dynamic recording devices. Each of the measurements above is categorized in **Table 1.1** as necessary, preferred, or helpful to assist in device selection. For dynamic data capture, digital fault recorders (DFRs) and distribution PMUs are two high-resolution devices that are useful in capturing transient events, but they are not the only devices available to record these quantities. In some instances, already installed revenue meters may provide this RMS information.[75]

**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[76] (see **Figure 1.3**) | |
| Examples of Recording Devices | Resource-side (SCADA) or demand-side (Advanced Metering Infrastructure (AMI)) 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 Current |
| Measurements Helpful if Available | Frequency, Apparent Power, Steady-State Current | Harmonics, Protection Element Status, Inverter Fault Code |

[74] This does not mean that every measuring device must calculate the quantities listed; however, the system used to collect, store, and transmit the measurements should perform the calculations. These calculations can be done on the sending, receiving, or archival end of the monitoring equipment system.

[75] These devices can also offer different measurement quantities. See Chapter 6 of NERC's Reliability Guideline on BPS-connected inverter devices, available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Inverter-Based_Resource_Performance_Guideline.pdf. 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.

[76] Individual distribution circuit data is not necessary but can be useful either in addition to or as replacement of T-D transformer data.

| Table 1.1: Recording Device Summary | | |
|---|---|---|
| **Topic** | **Steady-State** | **Dynamic** |
| **U-DER** | | |
| Useful Location(s) of Recording Devices | Point of interconnection of U-DERs; distribution substation feeder to U-DER location; aggregation point of multiple U-DER locations if applicable (see Figure 1.3) | |
| Examples of Recording Devices | DP SCADA or AMI; DER-owner SCADA | DFR, distribution PMU, modern digital relay, or other dynamic recording devices[77] |
| 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, Disturbance Characteristics,[78] Sinusoidal Voltage and Currents, Inverter Fault Codes. |

For protection quantities, the identified U-DER protection device informational flags, 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 becomes 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.

## Management of Large Quantities of DER Information

Management of the increasing diversity of DER functional settings from the various inverter vendors can become a challenge. Even once DPs, RCs, and TPs successfully coordinate DER functional settings, the reliable application of these settings to DERs in the field may not be ensured. Many DER manufacturers currently use "manufacturer-automated profiles" that preset certain functional parameters to the values specified in applicable rules (i.e., CA Rule 21, HI Rule 14H, or the default values of a certain IEEE 1547-2018 performance category). To date, these "manufacturer-automated profiles" are not validated by any third party, and verification by utility engineers is often limited to the review of a photo taken by a DER installer of the selected manufacturer-automated profile on the DER's general user interface at the time of commissioning. Given the criticality of DER trip and control mode settings for the BPS, more sophisticated verification methods are desired.

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

[78] 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 that are applied from the BPS perspective and the inclusion of this information can assist with both root cause analysis as well as verification of aggregate DER settings.

One solution is a "common file format" for DER functional settings, developed through a broad stakeholder effort by organizations like EPRI, IEEE, IREC, and SunSpec Alliance and now available to the public.[79] This effort defines a CSV file format with DER settings, specifying unique labels, units, data types, and possible values of standard parameters and leveraging the IEEE 1547.1-2020 standard's "results reporting" format. The report sets out rules to create CSV files that will be used to exchange and store DER settings. Potential uses for the common file format include:

- How utilities provide required settings, i.e., utility-required profile (URP) to the marketplace
- How developers take, map, and apply specified settings into the DER
- How DER developers provide the required proof of applied settings for new plants as part of the interconnection process
- How utilities internally store and apply their system-wide records of DER settings for planning and operational purposes, including exchange of DER voltage and frequency trip settings as well as settings for DER frequency-droop between DPs and TPs

One way to exchange these common DER settings files could be a central database (e.g., one hosted by EPRI). Authorized users can upload settings files, and all other users can download settings files to help exchange information among all applicable entities.[80] This central storage is recommended to reduce the information management and storage requirements for verification of DER models in bulk system studies.

[79] EPRI (2020): Common File Format for Distributed Energy Resources Settings Exchange and Storage. 3002020201. With assistance of Interstate Renewable Energy Council (IREC), SunSpec Alliance (SunSpec), Institute Electrical and Electronic Engineers (IEEE). Electric Power Research Institute (EPRI). Palo Alto, CA. Available online at https://www.epri.com/research/products/000000003002020201.
[80] EPRI launched a public, web-based DER Performance Capability and Functional Settings Database in 2020: https://dersettings.epri.com.

# Chapter 2: DER Steady-State Data Collection and Model Verification

This chapter describes the recommended data reporting requirements for collecting sufficient data to model aggregate DERs in Interconnection-wide power flow base cases. Each PC, in coordination with their TPs, should consider integrating these recommendations into their requirements per MOD-032-1 Requirement R1. After collecting the data for steady-state model verification for aggregate DERs, the first set of models to verify is generally this steady-state DER model due to how it feeds into many different studies, is the starting point for dynamic studies, and is generally the first stage of verifying the DER model.

## DER Modeling Needs for TPs and PCs

Modeling data requirements for steady-state aggregate DER data should be explicitly defined in the modeling data requirements established by each PC and TP per MOD-032-1. This section describes the recommended data and modeling practices for consistently representing the aggregate DERs in steady-state power-flow base cases. TPs and PCs generally model gross load and aggregate DERs at specific BPS buses or at distribution buses at the low-side of the T-D transformers, depending on their modeling practices. To accomplish modeling aggregate DER at the distribution bus, TPs and PCs need T-D transformer modeling data in order to explicitly assign the gross load and aggregate DERs connected to the modeled low-side bus. The TP and PC should establish DER data collection requirements for aggregate DER data at each T-D transformer so it can be modeled correctly.[81] DPs should have some accounting of DERs at the bus-level or T-D transformer level in coordination with TP and PC data reporting needs. The DP may need to use engineering judgment to support the TP and PC in gathering the data needed to develop suitable models.

DER models in the steady-state power flow base case, whether represented as a generator record or as a component of the load record, have specific data points that must be accurately populated to represent aggregate DERs.[82] These data points, on a bus-level or T-D transformer level, may include the following:

- Location, both electrical and geographic
- Type of DER (or aggregate type)[83]
- Historical or expected DER output profiles[84]
- Status
- Maximum and minimum DER active power capacity (Pmax[85] and Pmin)
- Maximum and minimum DER reactive power capability (Qmax, producing vars; Qmin, consuming VARs); alternatively, a reactive power capability curve for the overall U-DER facility (this is specific to U-DERs)

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

[82] Since the BPS models use aggregate or equivalent representations of the distribution system and DERs, these models are not expected to accurately represent the steady-state reactive capability of a DER at the T-D interface. The models provide a reasonable representation of aggregate equipment capability that may have some effect on BPS performance during contingency events. Modeling of this capability is important for contingency analysis and dynamic simulations.

[83] This may be defined as part of the generator name, generator ID, or load record ID, and may be useful as the DER penetration continues to increase and different types of DER may need to be tracked.

[84] If meter-level data is available, profiles of DER output help TPs and PCs understand how the DER should be dispatched in the power flow base case. This is essential for developing reasonable base cases that represent expected operating conditions of the BPS, including the operation of aggregate DERs. If metering data is not available in the area, default profiles are helpful for TP and PC base case creation.

[85] The preferred approach for variable (inverter-based) DERs is for the DP to provide total aggregate DER capacity and the TP and PC can set active power output (Pgen) of the DER in the power flow to an output level based on assumptions specified for each case. For large synchronous DERs, similar data collection requirements for steady-state modeling data can be used as would be used for BPS-connected resources.

- Distribution system equivalent feeder impedance[86]
- (U-DER) Reactive power-voltage control operating mode[87]

If one or more DERs are represented as a stand-alone generator record in the power flow, the TP and PC may need the following specific information to accurately represent this element (based on their specific modeling practices):

- Facility step-up transformer impedances
- Equivalent feeder or generator tie line[88] impedance (for large U-DER facilities), if applicable
- Facility or transmission-distribution transformer tap changer statuses and settings where applicable
- Shunt compensation within the facility[89]

The majority of newly interconnecting DERs across North America are either utility-scale solar PV (i.e., U-DERs) or rooftop solar PV (i.e., R-DERs) facilities. To reasonably represent these resources in the base case, the TP and PC may request that the DP or applicable DER aggregator[90] provide a reasonable estimate or differentiation between U-DERs and R-DERs. This may simply be a percentage value of the estimate of U-DERs versus R-DERs and possibly the number and size of U-DERs. While individual accounting of R-DERs is very unlikely and inefficient, typically the accounting of U-DERs is much more straightforward since these resources tend to be relatively large (e.g., 0.5 to 20 MW).[91]

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

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

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

86 This is useful for modeling both DER and load if there is a need to explicitly represent the recommended modeling framework in the simulation as opposed to the automatic tuning of this parameter by the composite load model.

87 TPs and PCs should consider local DER interconnection requirements regarding power factor and reactive power-voltage control operating modes, where applicable. These modes may include operation at a set power factor (e.g., unity power factor or some other static power factor level) or operation in automatic voltage control. TPs and PCs can configure the power flow models by adjusting Qmax, Qmin, and the mode of operation to appropriately model aggregate DERs.

88 In some cases, for generator tie line modeling, the MVA rating and length may be needed by the TP and PC.

89 This is based on DER modeling practices established by the TP and PC.

90 DER aggregators were introduced in FERC Order 2222 as an entity that can aggregate control over multiple resources, including DER and Demand Response. Order text available here: https://www.ferc.gov/sites/default/files/2020-09/E-1_0.pdf

91 These values are used as a guideline in the DER modeling framework; however, they can be adapted based on specific modeling needs.

| Table 2.1: Steady-State Power Flow Modeling Data Collection | |
|---|---|
| **Aggregate DER Modeling Information Needed**[92] | **Information Necessary for Suitable Modeling of Aggregate DERs** |
| Location | The DER interconnection location will need to be assigned to a specific T-D transformer or associated BPS or distribution bus based on the TP and PC modeling practices. Further specifying the colocation of DER to load also determines if the DER should be modeled closer to the head of the feeder or interspersed with load at the modeled load bus. Geographic location should also be given so that proper DER (e.g., solar) profiles and estimated impedance can be applied. |
| Type of DER (or aggregate type) | Specify the percentage of DERs considered U-DER and R-DER.[93] Provide an aggregate breakdown (percentage) of the types of DERs per T-D transformer. Preferably, this is specified as a percentage of aggregate DERs that are solar PV, synchronous generation, energy storage, hybrid[94] power plants, and any other types of DERs. |
| Historical or expected DER output profiles | For each type of aggregate DER (e.g., solar PV, combined heat and power, energy storage, etc.), specify a general historical DER output profile occurring during the studied conditions. What output are these resources dispatched to during peak and off-peak conditions? The TP and PC should define peak and off-peak conditions. |
| Status | Based on the DER output profile provided, TPs and PCs will know whether to set the aggregate DER model to in-service or out-of-service based on assumed normal operating conditions for the case. |
| Maximum DER active power capacity (Pmax) | Maximum active power capacity of aggregate DERs should be provided to the TP and PC. This, again, should be aggregated to the T-D transformer (i.e., each T-D transformer should generally have an amount of aggregated U-DER and R-DER, as necessary), depending on the TP and PC requirements. |
| Minimum DER active power capacity (Pmin) | Minimum active power capacity of aggregate DERs should also be provided, similar to maximum capacity. Systems with energy storage may have a Pmin value for aggregate DER modeling less than zero since the storage resources may be able to charge when generation DERs are at 0 MW output. |
| Reactive power-voltage control operating mode | Are the DERs controlling local voltage? Or are they set to operate at a fixed power factor? If some are operating in one mode while others are operating in a different mode, estimate the percentage in each mode using engineering judgment based on time of interconnection. |

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

[93] Consult with your TP and PC for more information on specific modeling requirements for U-DERs and R-DERs. Refer to NERC reliability guidelines: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_ModelingMerge_Responses_clean.pdf.

[94] Hybrid plants combine generation and energy storage and have different operational characteristics than either individual type of DERs.

| Table 2.1: Steady-State Power Flow Modeling Data Collection | |
|---|---|
| **Aggregate DER Modeling Information Needed**[92] | **Information Necessary for Suitable Modeling of Aggregate DERs** |
| Maximum DER reactive power capability (Qmax and Qmin)[95] | If DERs are controlling voltage (i.e., volt-var control), some aggregate reactive capability may need to be modeled. Otherwise, information pertaining to the expected power factor for DERs should be provided so that Qmax and Qmin can be configured in the model. For some U-DERs, a capability curve of reactive capability at different active power levels may be needed (at least at Pmax and Pmin levels).[96] Reactive devices required at the distribution bus to assist with voltage regulation and not otherwise aggregated in the DER model may also need to be represented. |

### Example of DER Information Mapping for Steady-State Power Flow Modeling

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

- 50 MW total aggregate DERs are allocated to T-D interface (per TP and PC modeling requirements)
- 35 MW are considered U-DERs and 15 MW are considered R-DERs (based on TP and PC modeling practices)
- Of the U-DERs, 20 MW are solar PV and 15 MW are BESS (i.e., ± 15 MW)
- Of the R-DERs, all 15 MW are solar PV
- About 75% of DER are likely IEEE 1547-2003 vintage and the remaining are most likely compliant with newer vintages of IEEE 1547 based on updated DP interconnection requirements
- Of all DERs, only 10 MW of the BESS U-DERs are electrically close to the feeder head and the remainder are interspersed with load.
- All DERs operate at unity power factor

## Steady-State DER Data Characteristics

As **Table 1.1** summarizes the measurement quantities necessary, 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 2.2** summarizes the many aspects related to using steady-state data 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 2.2** can be applied to both seasonal case verification as well as pre-contingency operating condition verification. Additionally, for steady-state verification, it is important to gather what mode other types of devices, such as Automatic Voltage Regulators, are in as they impact the voltage response.

95 Qmax refers to producing vars, and Qmin refers to consuming vars.

96 If this information is not known, the vintage of IEEE 1547-2018 standard could be useful to apply engineering judgment to develop a conservative capability curve.

| Table 2.2: 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.[97] SCADA data streams come in at typically 2–4 seconds per sample; however, these speeds are not always realizable. |
| Duration | Generally, a handful of instantaneous samples over a day will verify the dispatch of the DER and load for each Interconnection-wide base case. Durations nearing days or weeks of specific samples may be needed to verify 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. Data should be high accuracy regardless, however. |
| 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., global positioning system)[98] to align measurements from across the system. |
| Aggregation | Based on the modeling practices for U-DERs and R-DERs established by the TP and PC,[99] 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-DERs and R-DERs and having sufficient measurement data to capture each type in aggregate. Based on modeling practices by the TP and PC, this same process can be used to separate "fuel types" of the DER; for instance, separating out battery DERs from solar photovoltaic (PV) DERs if desired.[100] |

[97] The resolution needs to be able to reasonably capture large variations in power output over the measurement period.
[98] https://www.gps.gov/
[99] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_ModelingMerge_Responses_clean.pdf
[100] SPIDERWG has published a white paper specifically on BESS modeling available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/White_Paper_Distributed_Energy_Storage_Modeling.pdf

| Table 2.2: Steady-State DER Model Verification Data Considerations | |
|---|---|
| **Topic** | **Key Considerations** |
| 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 energy during times of solar irradiance, wind resources provide output during times of increased wind, and BESS may inject or consume energy based on market signals or other factors. In general, these recommendations can apply to sampling measurements for these resources:<br>• 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.<br>• Wind: Capture output patterns during coincident times of high solar PV output (if applicable) as well as high average wind speeds.<br>• BESS: BESS should be sampled during times when the resource is injecting in addition to when the resource is consuming power. |
| 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 a point on transmission that is not the normal delivery point. These same mappings apply to the dynamic model verification process.<br><br>In terms of data set completeness, data dropouts or other gaps in data collection should be eliminated by using hole filling or other interpolation techniques. A different set of data that does not have significant data gaps could alternatively be used. |
| 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 the operation mode for DERs may require coordination with distribution entities, 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 purposed for model verification. It is beneficial to include steady-state current and voltage waveforms to determine the operation mode, especially for inverter-based DERs.

## Steady-State DER Model Verification

Steady-state verification procedures can use lower time resolution data, and a tie is not required to a particular event. An entity in SPIDERWG provided an example of performing steady-state verification outside of an event on its system; when conducting short-circuit studies, it found that an aggregation of DERs was incorrectly modeled. In this scenario, the aggregation in question was DERs modeled as an aggregation of R-DERs. The R-DER aggregation was modeled on the nearest BPS bus at the incorrect voltage level. This was affecting the powerflow solution at the modeled BPS transformer and caused increased load tap changer activity in the powerflow model. The entity solved the issue in their studies by verifying the location of the resource and the connection voltage as well as analyzing the BPS bus path to get the appropriate impedances between the R-DERs and the BPS transformer. SPIDERWG recommends entities proactively verify their steady-state DER model based on steady-state conditions that are not related directly to an event.[101]

[101] For example, this can include voltage reduction tests, overnight low load conditions, or other operational conditions based on engineering judgement.

The TP should systematically verify their models as data becomes available.[102] This is to ensure their set of models is of high fidelity for their study's conditions. Important scenario conditions to verify include the following:[103]

- DER output at a (gross or net) peak demand condition
- DER output at some off-peak demand conditions
- When the percentage of DERs is significantly high[104]

In each of these scenarios, measuring the active and reactive power will help verify the steady-state parameters entered into the DER records. Voltage measurements will also help inform how the devices operate based on the inverter control logic, voltage control set points, and how these aggregate to the T–D interface. Engineering judgement should be used to correlate the captured measurements into parameter adjustments (e.g., T-D transformer impedance or Pmax of U-DERs) for the steady-state model where individual metering is not available.[105]

### Temporal Limitations on DER Performance

For many reasons, time-dependent DER operational characteristics can inhibit DER performance. For example, solar irradiance inherently limits the output of solar PV DERs. 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 or a different period chosen such that the limit is not applicable. Dispatch of DER off-maximum power should be carefully aligned with the steady-state and dynamic model parameterization,[106] especially the limits and control logic. The unavailability of such data should not stop the process as verification of other parameters can be performed.

**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 of their models.

## Steady-State Model Verification for an Individual DER Model

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 DER device characteristics may change in the day-to-day responses. This figure shows a sample seven-day week for a U-DER device that is set up to follow the local station load. Each valley in the figure corresponds to one day. Compare the response in **Figure 2.1** 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. Or, the TP for this particular site could verify the load-following nature by gathering this week of information and aligning it gross load.[107]

**Key Takeaway:**
The large majority of DER facilities are solar PV and behave generally like other BPS solar PV inverter-based resources. This predictable performance should be included when gathering data for model verification purposes.

---

[102] This may require coordination among both transmission and distribution entities such as PCs, RCs, and DPs.
[103] These examples are used to be in alignment with the conditions in TPL-001-4 (link: https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-4.pdf).
[104] This is typically decided based on engineering judgement and does not necessarily coincide with developed peak or off-peak Interconnection-wide base cases.
[105] This is likely the case for R-DERs; however, individual metering on U-DERs will reduce the amount of error in model verification.
[106] See NERC *Modeling Notification: Dispatching DER off of Maximum Power During Study Case Creation* available here: https://www.nerc.com/comm/PC/NERCModelingNotifications/Dispatching_DER_Off_of_Maximum_Power_during_Study_Case_Creation1.pdf
[107] In the steady state, the DER MW and MVAR output could be verified based on day four only. However, as this installation followed the nearby station load, a wider variety of samples were needed. To verify the load-following setting, day five provided valuable information regarding the load-following settings as the day was characterized by low load on the feeder and the DER dropped its output to follow that lower load to prevent back feeding.

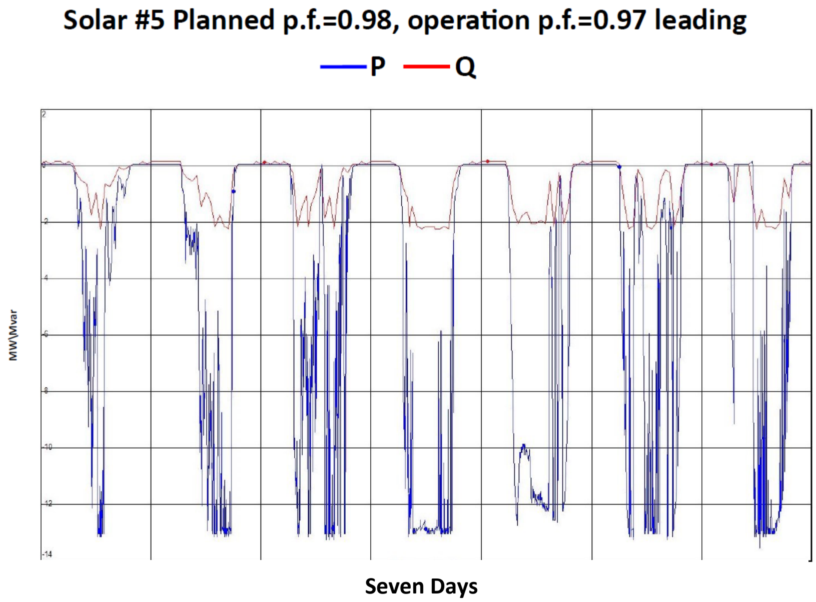


**Figure 2.1: Load Following U-DER Response**

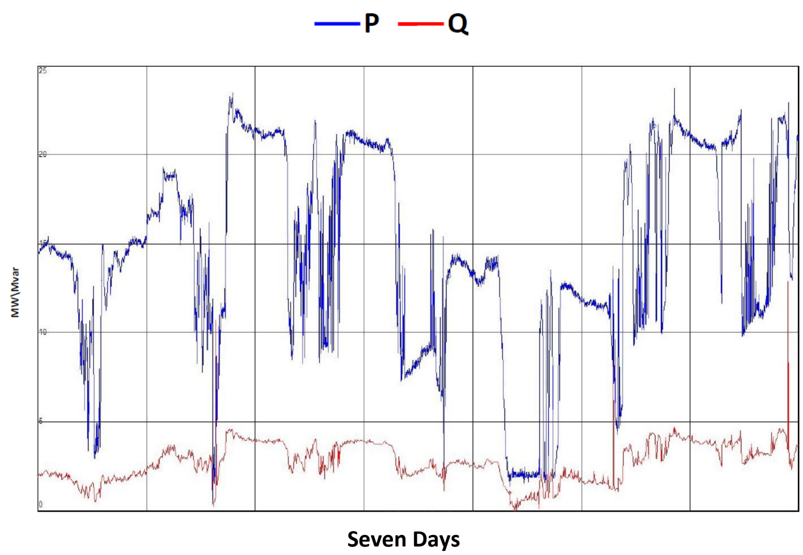


**Figure 2.2: Load Response near the U-DER**

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). Such separation and multiple measurement locations make the steady-state verification process easier. Each TP/PC should consult with the DP to make sure it is able to submit data required for the modeled aggregation as well as to identify critical measurement locations. If data measurements like **Figure 2.1** and **Figure 2.2** are not available, the TP can adjust its set of planning models to account for changes to the DER aggregation from the existing model by asking questions of the DP and applicable entities. **Table 2.3** highlights some of these important questions.

**Table 2.3: Sample DER Steady-State Questions and Anticipated Parameters**

| Data Collected[108] | Anticipated Parameters |
|---|---|
| What are the aggregated operational characteristics of DERs at the T-D interface within a specified time domain? | The collected data from this question will help set the maximum power output of all DER represented in the verification process. This accounts for the aggregated coincident capacity of the resources. |
| Where is the point of interconnection (i.e., transmission substation) for the aggregate DER? | This will identify which load/generator record to use in the powerflow set of data to attribute aggregate DER capacity. |
| What is the magnitude and type of aggregated coincident load connected to the transmission substation? | The collected data from this question will assist in determining capacities of various loads (e.g., motor load or electronic load) to determine how the overall model for the T-D interface will perform when adjusting both the DER model and load model. |
| What reactive capability is supplied at the DER installations? | The collected data from this question 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 to identify the power factor of major loads. |
| What is the minimum power of DER at the T-D interface? | For non-solar related DER devices such as microturbines or BESS, this parameter provides the minimum required output of the DER resource. |

### Battery Energy Storage System Performance Characteristics

For BESS, DER performance is highly dependent upon the control of the device. Understanding the operational characteristics of the BESS will allow the TP and PC to associate the steady-state interactions of load and the modeled BESS DERs. If the verified model consists of one or more BESS installations that cannot provide measurements per the TP and PC verification processes, DPs and other entities may need to contact the original equipment manufacturer or DER developer for answers to some of the questions in **Table 2.1**. Establishing good relationships with the BESS original equipment manufacturers will help DPs and other entities obtain useful type testing reports and other information that may answer the questions in **Table 2.1.** Regardless of how the DER is modeled, current practices include surveys or other written means to obtain an operational profile of BESS DER and help validate the parameters used in steady-state analysis.

Use of a single DER model for multiple DER types is recommended, but differing control design (e.g., IEEE 1547-2018 vs. IEEE 1547-2003) or modeling practices may dictate otherwise; moving to separate aggregations is related to the frequency or voltage regulation settings. The TP and PC should use engineering judgement and readily available information to determine if these considerations are necessary for their models and alter their verification practices to account for dual aggregation modeling accordingly.[109]

## Steady-State Model Verification for Aggregate DERs

The verification of multiple facilities 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 modeling many U-DERs and R-DERs at the T–D interface, some assumptions help the verification process. Most legacy DERs (e.g., IEEE 1547-2003) may operate at

[108] These questions are useful for BESS DERs as well as other technology types of DERs. These questions are not to be used in lieu of more detailed modeling requests to develop the initial set of models but rather implemented to check the parameterization of already established models.

[109] SPIDERWG has developed a white paper outlining modeling practices here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/White_Paper_Distributed_Energy_Storage_Modeling.pdf

constant power factor mode only and are typically set at unity power factor, making it a safe assumption to not adjust those modes for models representing legacy DERs. The IEEE 1547-2018 standard has introduced more DER operating modes (e.g., volt-var, watt-var, or volt-watt), and this may require reaching out to the DP to verify as the settings could be represented in a piecewise function 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 while leaving the monitoring of R-DER at the high side of the T–D interface as per **Figure 1.3.**

**Figure 2.3** shows example measurements from a 44 kV feeder. The four solar plants in the figure, each rated 10 MW, and one major industrial load are connected to the feeder at different electrical 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 that travel through a long feeder with a low X/R ratio. The data show that the third solar plant's reactive power output was opposite to the planned direction (i.e., 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 can verify the aggregate of the U-DER solar facilities as the MW and MVAR flows from these facilities were recorded. Additional confirmation of steady-state voltage settings would require the voltages at these locations and such measurements are recommended to supplement these graphs. From the graphs, the following steady-state DER values (assuming DER is at maximum output) would be compared against the modeled representation and corrected:

- Aggregate U-DER at 40 MW production from Solar 1, 2, 3, and 4
- Aggregate R-DER at ~6 MW from the difference in one day on the Load graph
- Gross load at ~14 MW

The R-DER steady-state component and the gross load component would be difficult to gather from the single load measurement alone. However, careful engineering judgement can help separate the DER from the load in those measurements. Additionally, it is important to calculate the power factor of the aggregate DER over any one DER installation. While the largest discrepancy is between the 0.995 leading versus 0.994 lagging power factor, correcting that installation isn't as important as correcting the total capacity of the aggregation. In the aggregation, at maximum power production the aggregate produces two (0+1.5+1.5-1) MVAR. This equates to the aggregate operating at 0.999 leading power factor.

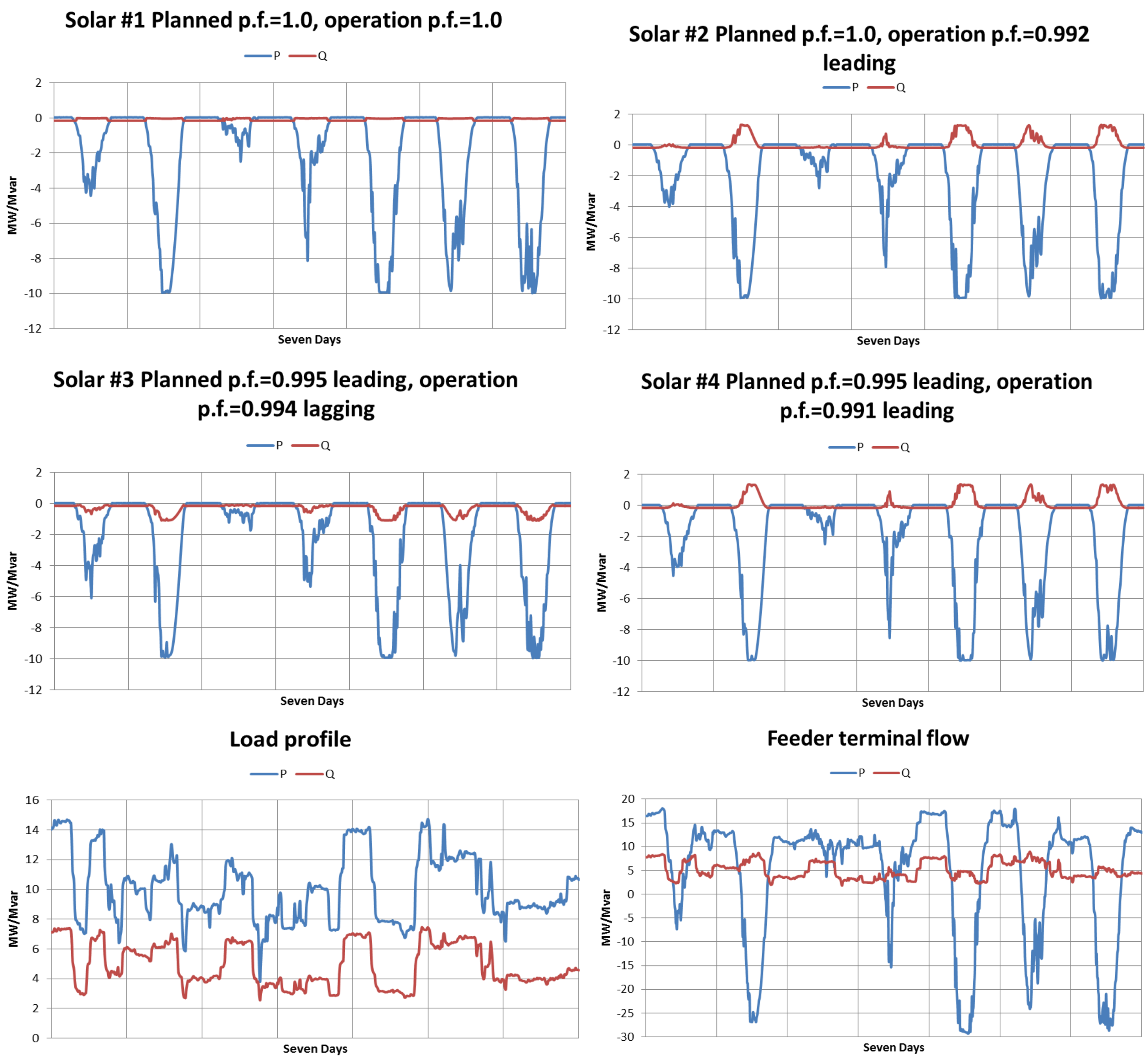


**Figure 2.3: Active and Reactive Power Measurements from U-DERs, Load, and Substation**

**Figure 2.4** shows another example taken from a 230 kV load-serving substation. Power trends from eight monitored[110] DERs connected to 44kV feeders supplied from the station are plotted in the figure. Note that the sixth solar DER is a behind-the-meter (BTM) installation, the seventh is a biomass DER and the eighth is aggregation of three solar DERs and load.[111] The last two plots in **Figure 2.4** are measured from two paralleled 230kV-44kV step-down terminals. As shown, nearly zero MW was transferred across the transformers under high DER outputs. The Mvar flow steps were a 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. This process may require baseline measurements to determine gross load values in addition to substation level output for both load and DER. As evident in this example with the capacitor bank switching, DER and load output affects the T–D transformer.

[110] The meter at Solar #2 was out of service that week due to a failed current transformer.

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

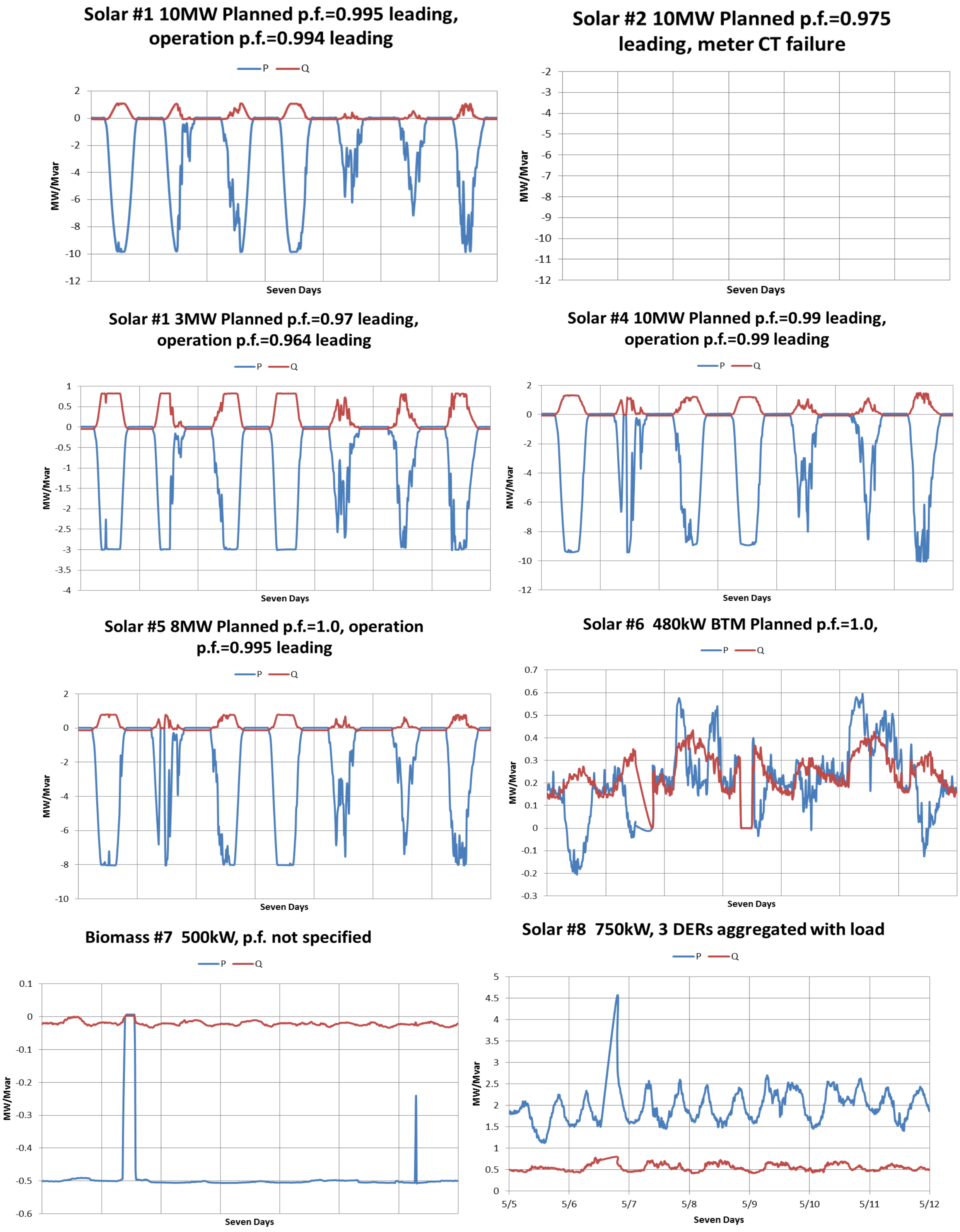


**Figure 2.4**: **Active and Reactive Powers Measured from Various DERs and Substation Transformers**

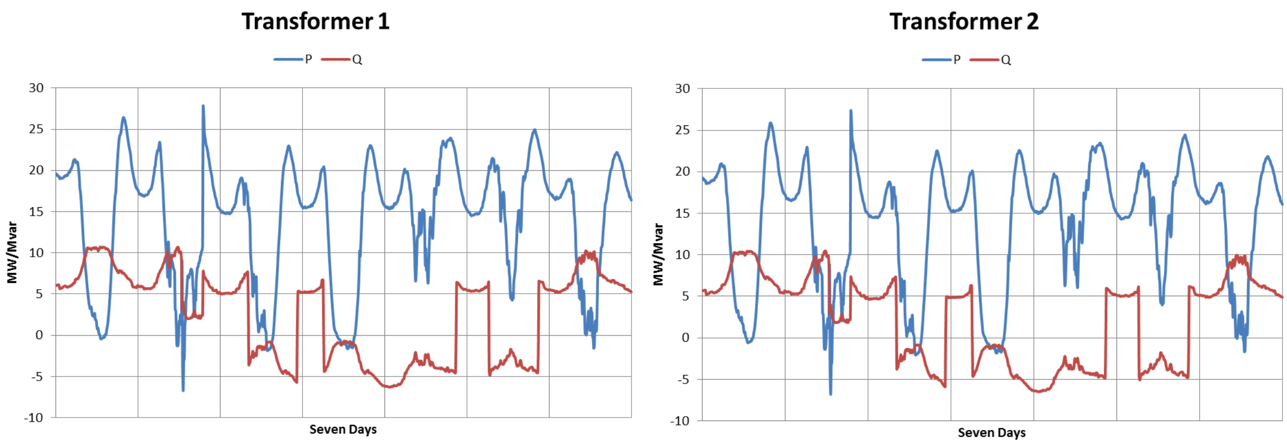


**Figure 2.5: Active and Reactive Powers Measured from Various DERs and Substation Transformers**

As with the aggregations in **Figure 2.3**, the TP or PC can use the active and reactive output measurements from the substation transformers and the DERs to account for the steady-state representation of the DER and load for cases that are to represent conditions during this time. Even with failures to send data from specific U-DER facilities, the verification procedure can occur as long as assumptions are made. The following points can be deduced from **Figure 2.4,** assuming the 10 MW U-DER solar facility also acts similarly to the others fed off the parallel transformers:

- Aggregate U-DER production of 40.5 MW from the solar and biomass graphs except for the ones BTM
- Aggregate R-DER production of about 1.5 MW from the daily changes in the BTM solar load
- Gross load of about 40–42 MW taken from both transformer graphs and backing out the aggregate DER (both U-DER and R-DER) production

In **Figure 2.4**, since one of the U-DER-modeled DERs did not have measurements, the TP and PC can either assume it operated with the planned power factor or wait for the metering to be restored. However, it should be clear from both **Figure 2.3** and **Figure 2.4** that such measurements allow the TP and PC to verify their models such that DER behavior is adequately modeled in their simulations. For instance, if these T–D interfaces simply modeled a net load during peak conditions, they would be ignoring nearly 55 MW of gross load. Doing so will impact the simulated performance of the transmission substation.

## Steady-State Model Verification Changes with Increasing Generator Records

> **Key Takeaway:**
> Increasing the number of generator records for representing DER in the simulation increases the importance of having on-site measurements available for model verification.

Once the model contains significant amounts of U-DERs and R-DERs, the dispatch of the modeled 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 served from the substation, a TP can verify the MW and MVAR output between the two aggregations as long as the gross load of the feeder is known. **Figure 2.5** reiterates recommended SPIDERWG modeling framework showing two points of record where DERs connect -- a DER connected near the substation or a DER further out on the feeder and closer to load. 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 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, verification of the steady-state MW, MVAR, and V characteristics will need measurements of those quantities and which of the DER model inputs those measurements pertains to (i.e., the U-DER or R-DER representation). Additionally, some modeling practices have more than one generator record for different aggregations of DER technology types. The increase of generator records when modeling DER increases the importance of monitoring individual large U-DER facilities to attribute the correct steady-state measurements to the planning models. In the case of large amounts of U-DER and R-DER at the T-D interface, assumptions are required to categorize the metered DER response in relationship to the non-metered DER response. SPIDERWG recommends measurement equipment be required for the U-DER behind a T-D interface to reduce the impact these assumptions have on model quality.

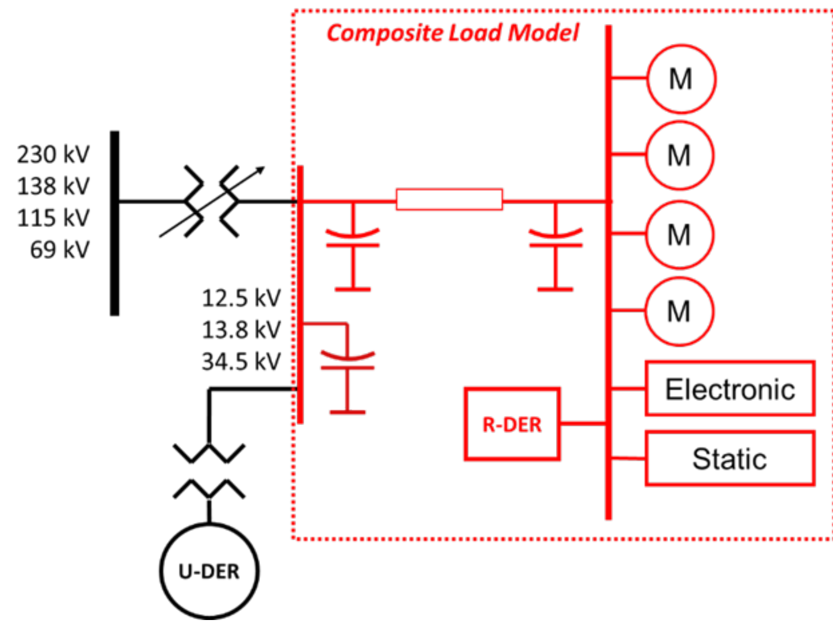


**Figure 2.6**: **Aggregate U-DER and R-DER Steady-State High Level Representation**

# Chapter 3: DER Dynamic Data Collection and Model Verification

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

## DER Modeling Needs for TPs and PCs

Transient dynamic modeling data requirements for aggregate DERs should be explicitly defined in each PC and TP's modeling data requirements per MOD-032-1. This section describes the recommended data and modeling practices for consistently representing the aggregate DER in dynamic simulations performed by TPs and PCs to ensure BPS reliability. Refer to the existing NERC reliability guidelines[112] regarding DER modeling for more information about recommended dynamic modeling approaches for DERs. While synchronous DERs exist and some new synchronous DERs are being interconnected in varying degrees,[113] inverter-based DERs (e.g., solar PV and battery energy storage) are rapidly being interconnected to the system in many areas across North America. Therefore, this section will use the DER_A dynamic model as an example for describing necessary information for purposes of developing DER dynamic models.

The DER_A dynamic model is the recommended model for representing inverter-based DERs (i.e., wind, solar PV, and BESS).[114] The DER_A model is appropriate for representing U-DERs and R-DERs as a standalone generator record or as a component of the load model (e.g., using the composite load model). The TP and PC will need to specify what their modeling practices are regarding U-DERs and R-DERs, including but not limited to the following:

- How are U-DER and R-DER differentiated in the planning base cases?
- Is a size threshold used to differentiate resources, or is this based on location along the distribution feeder(s)?
- Are the details of DER data different in any way between U-DERs and R-DERs?
- Are there specific interconnection requirements applicable to U-DERs, R-DERs, or both?
- Are U-DERs expected to have higher performance requirements for participating in energy markets?
- Are DERs combining generation and energy storage (i.e., hybrid plants), are these technologies ac-coupled or dc-coupled, and what are the operational characteristics of the facility (i.e., how is charging and discharging of the energy storage portion modifying total plant output)?
- What are the specific distribution-level tripping schemes or return-to-service requirements that would apply during the dynamics time frame for different vintages of DER installation dates?
- Are DERs generally located near the distribution substation or closer to the end-use loads?
- Are there any BPS protection schemes (e.g., direct transfer trip) that could result in the disconnection of DERs under certain BPS configurations?

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112 Reliability guidelines are available here: https://www.nerc.com/comm/Pages/Reliability-and-Security-Guidelines.aspx

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

114 The New Aggregated Distributed Energy Resources (der_a) Model for Transmission Planning Studies: 2019 Update, EPRI, Palo Alto, CA: 2019, 3002015320 https://www.epri.com/#/pages/product/000000003002015320/?lang=en-US.

- Are U-DERs or R-DERs expected to employ momentary cessation for large voltage excursions?

The DER_A dynamic model consists of many different parameter values that represent different control philosophies and performance capabilities for aggregate or individual inverter-based DERs; however, most of the parameter values remain fixed when representing different DER vintages or specific distribution-level interconnection requirements.[115] Therefore, it is important to focus on the control modes of operation and parameter values that change based on what types and vintages of DERs are connected to the distribution system. The following section will describe how gathering this data can be a fairly straightforward task and provide adequate information for the TP and PC to be able to use engineering judgment to model aggregate DERs in their footprint.

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

As mentioned, the complexity and number of parameter values of the DER_A dynamic model should not prohibit or preclude entities from developing relatively straightforward information for TPs and PCs to use to model these resources. **Table 3.1** shows how parameterization of the DER_A dynamic model can be mapped to questions that should be asked by the TP and PC and to information that should be provided by the DP or other external entity to help facilitate DER model development. Note that **Table 3.1** shows default DER_A parameters to capture the general behavior of DERs compliant with IEEE 1547-2018 Category II; they are taken from NERC *Reliability Guideline: Parameterization of the DER_A Model for Aggregate DER*.[116] The table describes IEEE 1547 and its various versions; however, the concepts would also apply to other local or regional rules, such as California Rule 21 or Hawaii Rule 14H. Values listed in red are those that are likely subject to change across different vintages of the IEEE 1547 standard and would likely need to be modified to account for systems with DERS with varying vintages of IEEE 1547. The questions posed in this guideline are intended to help TPs and PCs reasonably parameterize the DER_A dynamic model based on the information received. Refer to **Appendix B** for considerations for distributed energy storage systems.

**Table 3.1** is an example to help illustrate how the TP and PC could map questions related to DER information to develop an aggregate DER dynamic model. The order of parameters and exact names of parameters may be slightly different across software platforms. Refer to a specific software vendor model library for exact parameter names and order of parameters. However, the concepts can be applied across software platforms.

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

| Param | Default | Information Necessary for Suitable Modeling of Aggregate DERs |
|---|---|---|
| *trv* | 0.02 | Parameter values do not generally change between vintages of IEEE 1547. For the purposes of modeling, these default parameters are appropriate. Any dynamic voltage support requirements set by the DP should be communicated to the TP and PC so they can determine an appropriate modeling practice. Note that these parameters can be used to represent either dynamic voltage support or steady-state volt-var functionality; TPs and PCs will need to determine which approach is being used and specify any data collection requirements accordingly. |
| *dbd1* | -99 | |
| *dbd2* | 99 | |
| *kqv* | 0 | |
| *vref0* | 0 | |
| *tp* | 0.02 | |
| *tiq* | 0.02 | |

[115] For example, the parameters could represent DERs compliant with different versions of IEEE 1547 (e.g., -2003, -2018, etc.) or DP-specific interconnection requirements. For those settings that can be remotely managed and written per Clause 10 of IEEE 1547-2018, the TP and PC should specify how a management system can send information to update their models when such changes alter the control of the aggregate DER model and thus impact the T-D interface.

[116] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_ModelingMerge_Responses_clean.pdf

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

| Param | Default | Information Necessary for Suitable Modeling of Aggregate DERs |
|---|---|---|
| *ddn* | 20 | Are DERs required to have frequency response capability enabled and operational for overfrequency conditions, as in do DERs respond to overfrequency conditions by automatically reducing active power output based on this type of active power-frequency control system? If so, what are the required droop characteristics for these resources (e.g., 5% droop would equal a *ddn* gain of 20)?[117] What is the estimated fraction of resources installed on your system that are required to have this capability (based on interconnection date and requirements)? |
| *dup* | 0 | Are DERs required to have frequency response capability enabled and operational for underfrequency conditions, as in if there is available energy, do DERs respond to underfrequency conditions by automatically increasing active power output based on this type of active power-frequency control system? Are there any requirements for DERs to have headroom to provide underfrequency response? If so, what are the required droop characteristics for these resources? What is the estimated fraction of resources installed on your system that are required to have this capability (based on interconnection date and requirements)? |
| *fdbd1* | -0.0006 | If frequency response capability is enabled and operational, the deadband should be set to match any interconnection requirements governing this capability and performance. Consider the different types of interconnection requirements and what the correct assumption would be for this parameter, where applicable. |
| *fdbd2* | 0.0006 | If frequency response capability is enabled and operational, the deadband should be set to match any interconnection requirements governing this capability and performance. Consider the different types of interconnection requirements and what the correct assumption would be for this parameter, where applicable. |
| *femax* | 99 | Values vary based on the IEEE 1547 vintage of the DERs, so a time line of interconnection capacity that estimates the amount and timing of DER interconnection will support modeling. |
| *femin* | -99 | Values vary based on the IEEE 1547 vintage of the DERs, so a time line of interconnection capacity that estimates the amount and timing of DER interconnection will support modeling. |
| *pmax* | 1 | Parameter values do not generally change between vintages of IEEE 1547. No information is needed from the DP for purposes of modeling, assuming these default parameters are appropriate. In cases where the TP or PC has determined that these default parameters are not appropriate, the TP or PC may request additional information of the DP for this purpose. |
| *pmin* | 0 | |
| *dpmax* | 99 | |
| *dpmin* | -99 | |
| *tpord*[118] | 5 | |
| *Imax* | 1.2 | |
| *vl0* | 0.44 | |
| *vl1* | 0.49 | |
| *vh0* | 1.2 | |
| *vh1* | 1.15 | |
| *tvl0* | 0.16 | |
| *tvl1* | 0.16 | |
| *tvh0* | 0.16 | |
| *tvh1* | 0.16 | |
| *Vrfrac* | 1.0 | Values vary based on the IEEE 1547 vintage of the DERs, so a time line of interconnection capacity that estimates the amount and timing of DER interconnection will support modeling. |

[117] Note that TPs and PCs will need to consider the fraction of DERs providing frequency response, if applicable. The values of *ddn* and *dup* will need to be scaled appropriately to account for this fraction. The gain value can be determined by scaling (1/droop) by the fraction of DERs contributing to frequency response. This concept applies to *dup* as well.

[118] The active power-frequency response from DERs, if used in studies, should be tuned to achieve and ensure a closed-loop stable control. This parameter may need to be adapted based on this tuning.

| Table 3.1: Data Collection for Parameterizing the DER_A Dynamic Model | | |
|---|---|---|
| **Param** | **Default** | **Information Necessary for Suitable Modeling of Aggregate DERs** |
| *fltrp* | 56.5 | Values vary based on the IEEE 1547 vintage of the DERs, so a time line of interconnection capacity that estimates the amount and timing of DER interconnection will support modeling. |
| *fhtrp* | 62.0 | Values vary based on the IEEE 1547 vintage of the DERs, so a time line of interconnection capacity that estimates the amount and timing of DER interconnection will support modeling. |
| *tfl* | 0.16 | Parameter values do not generally change between vintages of IEEE 1547. No information is needed from the DP for purposes of modeling, assuming that these default parameters are appropriate. In cases where the TP or PC has determined that these default parameters are not appropriate, the TP or PC may request additional information from the DP for this purpose. |
| *tfh* | 0.16 | |
| *tg* | 0.02 | |
| *rrpwr* | 2.0 | Values vary based on the IEEE 1547 vintage of the DERs, so a time line of interconnection capacity that estimates the amount and timing of DER interconnection will support modeling. |
| *tv* | 0.02 | Parameter values do not generally change between vintages of IEEE 1547. No information is needed from the DP for purposes of modeling, assuming that these default parameters are appropriate. In cases where the TP or PC has determined that these default parameters are not appropriate, the TP or PC may request additional information from the DP for this purpose. |
| *Kpg* | 0.1 | Values vary based on the IEEE 1547 vintage of the DERs, so a time line of interconnection capacity that estimates the amount and timing of DER interconnection will support modeling. |
| *Kig* | 10.0 | Values vary based on the IEEE 1547 vintage of the DERs, so a time line of interconnection capacity that estimates the amount and timing of DER interconnection will support modeling. |
| *xe* | 0.25–0.8[119] | Parameter values do not generally change between vintages of IEEE 1547. No information is needed from the DP for modeling purposes, assuming that these default parameters are appropriate. In cases where the TP or PC has determined that these default parameters are not appropriate, the TP or PC may request additional information from the DP for this purpose. |
| *vfth* | 0.3 | TP and PC engineering judgment can be used to set this parameter value; may be subject to change across vintages of IEEE 1547 for the purposes of modeling. |
| *iqh1* | 1.0 | Parameter values do not generally change between vintages of IEEE 1547. No information is needed from the DP for modeling purposes, assuming that these default parameters are appropriate. In cases where the TP or PC has determined that these default parameters are not appropriate, the TP or PC may request additional information from the DP for this purpose. |
| *iql1* | -1.0 | |
| *pfflag* | 1 | |
| *frqflag* | 1 | |
| *pqflag* | Q priority | Values vary based on the IEEE 1547 vintage of the DERs, so a time line of interconnection capacity that estimates the amount and timing of DER interconnection will support modeling. |
| *typeflag* | 1 | What is the penetration of energy storage resources connected to the distribution system? What percentage of DERs are energy storage? Are these larger utility-scale energy storage DERs, or more distributed (e.g., residential) energy storage DERs? Any values or estimates as to the interconnection of energy storage DERs will help determine whether to and how to separate out energy storage DERs in the models. |

Table 3.1 highlights that the interconnection time line is critical for creating dynamic models of aggregate DERs because DER capabilities and performance are dominated by the interconnection requirements set forth on those DERs. TPs and PCs may have additional data points that are useful for capturing more information relevant to developing reasonable DER models; they also may have other data points needed to model larger U-DER installations if such additional requirements or data are needed. For DER model parameter values that vary with the vintage of IEEE 1547, a time line of interconnection capacity can be shared to estimate the amount and time in which resources were interconnected, which can be used to estimate the makeup of various IEEE 1547 vintages. TPs and PCs will also need to consider what the expected settings of the actual installed equipment[120] may be; this can be informed by any interconnection requirements or expected default settings used.

[119] Studies performed by EPRI have shown that *Xe* may need to be a greater value in certain systems or for certain simulated faults to aid in simulation numerical stability. These studies have shown that the increased *Xe* value does not reduce the reasonability of the DER response.
[120] As opposed to the estimation that is made from using the time of interconnection for the general capacity of DER

To recap the relevant information needed for aggregate DER dynamic modeling, the following data points should be considered by TPs, PCs, DPs, and other entities in the development of requirements and when providing this information for modeling purposes:[121]

- What is the vintage of IEEE 1547 (or equivalent standard) that is applicable to the DERs and were there any applicable updates to DP interconnection requirements regarding DERs? If it is a mixed collection of vintages, based on the interconnection date, engineering judgment should be used by the DP, TP, and PC to assign percentages to different vintages, as applicable.
- Do the installed or projected future installations of DERs have the capability to provide frequency response in the upward or downward direction? If so, are there any relevant requirements or markets in which DERs may be dispatched below maximum available active power?
- Are DERs providing dynamic voltage support or any fault current contribution or are they entering momentary cessation?
- What are the expected trip settings (both voltage and frequency) associated with the vintages of IEEE 1547 or other local or regional requirements that may dictate the performance of DERs?
- Are DERs installed on feeders that are part of UFLS programs? If so, more detailed information regarding the expected penetration of DERs on these feeders may be needed. As stated previously, hybrid U-DER facilities likely need specific, more detailed modeling considerations by the TP and PC, and therefore should be differentiated accordingly.

## Dynamic DER Data Characteristics

Dynamic recorders used to capture the transient conditions of an event have different data considerations than the steady-state recording equipment. The data characteristics and considerations for recording measurements used in transient dynamic model verification are found in **Table 3.2.** In comparison to steady-state measurements, dynamic data measurements require a faster sampling rate with the trade-off that the higher fidelity sampling is for a shorter time period. The data captured from dynamic disturbance recorders can be used for dynamic model verification.

**Table 3.2: Dynamic DER Model Verification Data Considerations**

| Topic | Key Considerations |
|---|---|
| Resolution | 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 effects. Therefore, a resolution on the order of 1–4 milliseconds is recommended to be above the Nyquist Rate for these effects. For reference, typical sampling rate recording devices can report at 30–60 samples per second continuously, with some newer technologies sampling up to 512 samples per cycle for specific triggers. |

[121] The TP and PC will need to consider these points when developing aggregate DER dynamic models and, therefore, will need information from the DP and any other entities that may be able to help provide information in these areas.

| Table 3.2: Dynamic DER Model Verification Data Considerations | |
|---|---|
| **Topic** | **Key Considerations** |
| 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 those that detect a BPS fault or accept nearby protection relays that trigger the device to record. This generally shows up as the following:<br>• Positive sequence voltage is less than 88% of the nominal voltage[122]<br>• Over-frequency events[123]<br>• Under-frequency events<br>Although more sensitive 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. In the transmission system model, the DER terminals are expected to have the same electrical frequency. Additionally, a high voltage trigger should be implemented for areas that are also concerned with verification of DER due to overvoltage conditions. |
| Duration | An event duration requirement depends on the dynamic event to be studied. SPIDERWG recommends a recording window of at least 15 seconds for DER model verification.[124] For longer 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. Typically, the recording devices will use the same instrumentation as the protection system, which already has a high level of accuracy. |
| Time Synchronization | Dynamic measurements should be time synchronized to a common time reference (e.g., global positioning system) 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.[125] |
| Aggregation | Based on the modeling practices for U-DERs and R-DERs established by the TP and PC, 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-DERs and R-DERs and having sufficient measurement data to capture each type in aggregate. Similar to **Table 2.1**, it may also be necessary to separate the U-DERs or R-DERs by operational characteristics based on the TP's and PC's modeling practices. |

[122] This value is presented as an example based on prior event analysis reports. Entities are encouraged to decide on trigger thresholds based on their experience of the local system.

[123] Both over- and under-frequency 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.

[124] Even if a 15-second window is not available for an event, TPs and PCs should use what is available and determine its worth for model verification.

[125] Per PRC-002-3, sequence of events recording and fault recording data shall be time synchronized for all BES busses per R10 (available here: https://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-002-3.pdf ). This same concept should be true for these measurements that may not be taken from BES buses.

| Table 3.2: Dynamic DER Model Verification Data Considerations | |
|---|---|
| **Topic** | **Key Considerations** |
| Data Format | Similar to the steady-state data, the dynamic data formats typically come in a delimited file type that can be read by Microsoft Excel. If it does not come in a known Excel format, ASCII[126] files are typically used that can be converted into a file format readable in Excel. However, other file types, such as COMTRADE,[127] are also widely used by recording devices and can be expected when requesting dynamic data from these recording devices. |
| Post-Processing | In terms of data set completeness, data gaps should be minimized not through interpolation but through careful selection and archival of event recordings. This is in contrast to the steady-state data key consideration that would recommend interpolation to fill data gaps. |

## 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. It should be noted that many of these events will not coincide with a defined "system peak" or "system off-peak" condition. 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 of DER response from load response in events, both in steady-state and dynamics performance
- Reduction strategies to simplify 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 as follows:

- Events that occur during DER nonoperational or disconnection periods
- Other events that do not contain a large signal response of DERs (e.g., events in areas with very low instantaneous penetration of DERs)

Selecting multiple events for validation will provide TPs additional assurance on the validity of the dynamic DER model rather than selecting the "perfect" event. This should be done even for already verified DER models. One of the most important aspects of adding an event to play back in simulation is that the event cause code is different for the previously used events and the new event.[128] Based on the above factors, it is crucial to the model verification process that each recorded event have sufficient detail to illustrate 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 wide-area and DER models.

## DER Dynamic Model Verification for a Single Aggregation

If the transmission model contains DER models, those models should adequately represent dynamic performance of aggregate DERs. U-DERs and R-DERs differ in that dynamic performance characteristics of individual installations of U-DERs are likely accessible while the dynamic performance characteristics of individual installations of R-DERs are

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

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

[128] Additionally, events are not the only method by which dynamic changes of behavior may be impacted. For instance, voltage reduction tests may have portions of recordings that are useful to play back into the model in the same way an event recording would. These should also be explored by TPs and PCs to verify their models.

not. By having the individual performance readily available, the TP or PC can tune their transmission models that represent those resources.[129] If the DP/TP/PC has access to the commissioning tests of the individual U-DER, these results are also useful in DER model verification as some commissioning tests demonstrate the full dynamic capability of the installed devices.

With data made available, model verification can occur. See **Figure 3.1** for a high-level representation of the recommended modeling framework that will be used in this section to describe the topology with load and other modeled components. In order to separate out the contributions from the DER and the load, engineering judgement must be used in reading net load jumps[130] from events, coupled with a deep understanding of the nature of load in that particular area. The TP or PC can disaggregate the response, using these points to start attributing the response. The measurement taken at the T–D interface will represent the responses of all the components of the equipment in **Figure 3.1**, and it is not the goal to separate the measurement to its respective parts and verify the components separately. Rather, the goal is to verify the cumulative (composite load + DER) response to the aggregate[131] models to a reasonable state for its representation in transmission models.[132] Examples of data collection for this guideline are in **Appendix F**.

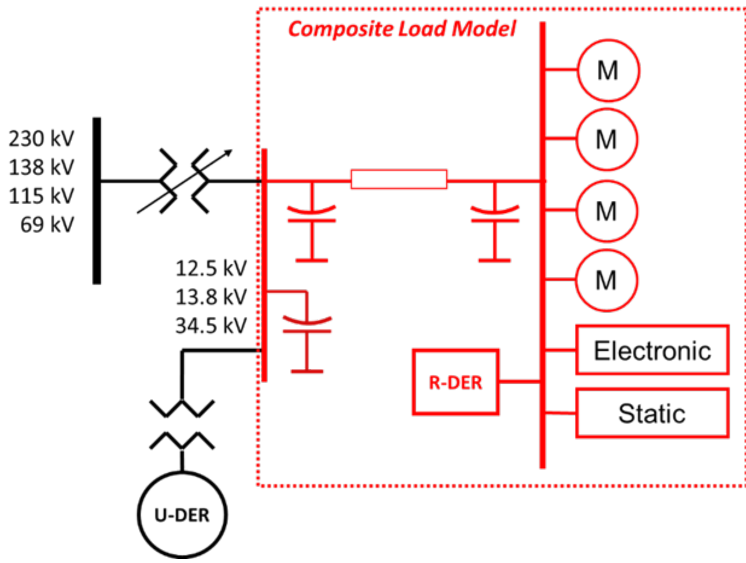


**Figure 3.1: High Level Individual U-DER and Load Model Topology**

## Dynamic Parameter Verification without Measurement Data

In 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 its 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 3.3**. This list of parameters is not exhaustive in nature. This table should be altered to address the modeling practices the entity uses[133] in representing aggregate DER in its set of BPS models

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

[129] This is the case whether using an aggregate dynamic model (such as DER_A), an individual dynamic model set (such as the second-generation renewable models) or a synchronous model. Because U-DERs generally will dominate the model performance, individual U-DER performance can verify a majority of T-D interfaces in the transmission model.

[130] For net load recorded at the high side of the T-D transformer

[131] Note that both the composite load model and the DER_A model are aggregate models that represent aggregate equipment.

[132] The Load Modeling Task Force has developed a reference document on the nature of load here. A NERC disturbance report located here has demonstrated the net load jumps and deals with this at a high level. EPRI has also published a public report that details this, available here.

[133] Primarily this is due to interconnection requirements but can also be due to other external documents.

and should be used to guide dynamic performance verification. These parameters can be used to help adjust the model to assist in performing the iterative verification process. As the DER_A model is one of the few current dynamic models provided for representing inverter-based 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[134] 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 DERs 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.

**Table 3.3: DER Dynamic Model Data Points and Anticipated Parameters**

| Data Collected | Anticipated Parameters | Example DER_A parameters |
|---|---|---|
| What equipment standards are applicable to the inverters represented? | This will provide a set of voltage and frequency trip parameters. In general, this question can be answered by asking for the installation date, which correlates with the IEEE 1547 standard version date. This, however, will not be 100% accurate due to differences in jurisdictional approval of each version of the IEEE 1547 standard. | Voltage:<br>vl0,vl1,vh0,vh1,tvl0,tvl1,tvh0,tvh1<br><br>Frequency:<br>Fltrp,fhtrp,tfl,tfh<br><br>Overall:<br>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 it can represent choices made inside the vintage. | Voltage:<br>Vrfrac<br><br>Frequency:<br>Handled by the Ffrac block[135] |
| What interruptible load is represented at the substation? | This data point will allow TPs and PCs to coordinate the load response with the DER response. The information provided here can be used in other parts of the model verification process. If the DER model is part of a composite load model, this question becomes more important than if the DER has a standalone model. | If used as part of a composite load model:<br>Vrfrac<br><br>If standalone:<br>N/A |

## Dynamic Parameter Verification with Measurement Data Available

The preferred method for dynamic parameter verification is matching 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 TSP.[136] Per

[134] Or other equivalent applicable equipment standard

[135] Unlike voltage trip there is no concept of "partial frequency trip" in the DER_A model. What "partial voltage tripping" means is that after a voltage event depending on the voltage level, a fraction, Vrfrac, may recover. For frequency, if the frequency violates the Fltrp/tfl and Fhtrp/tfh, the entire DER_A trips. No external model is needed for this. This feature is already included in DER_A.

[136] Order No. 828, 156 FERC ¶ 61,062

FERC Order No. 792, metering data is also provided to the transmission provider.[137] Thus, the TP/PC has access to data for verification of U-DER dynamic performance for units applicable to the SGIA. In utilities with larger DER penetrations, 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, the data[138] should be sent in order to verify the aggregated impact of U-DER installations in the BPS Interconnection-wide base case set of models.

While the SGIA allows the TP/PC to obtain data for SGIA-applicable units, not all DER facilities will be under a SGIA. For example, **Table 3.4** shows the resources the Independent System Operator New England, Inc., (ISO-NE) considers as DERs. For DERs listed here, 1,532 MW of the solar PV generation is not participating in the wholesale market while 858 MW participates and is SGIA-applicable. In this area, reliance on the SGIA alone will only apply to a third of the installed solar PV DER. In addition, generation from other sources totals 1,351 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 DERs applicable to the SPIDERWG Coordination Group's definitions would be verified if only those facilities under the SGIA were verified. This shows that, while the SGIA plays a role in the data collection, reliance on the SGIA alone could result in significant data gaps. The TP/PC should use measurement devices discussed in **Chapter 1** to gather measurements where feasible.

**Table 3.4: ISO-NE Distributed Energy Resources as of 01/01/2018**

| DER Category[139] | Settlement-Only Resource Nameplate Capacity [MW] | Demand Resource (DR) Maximum Capacity [MW] | Total DER Capacity [MW] |
|---|---|---|---|
| Energy Efficiency | - | 1,765 | 1,765 |
| Demand Resources (excluding BTM 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 |

[137] Order No. 792, 145 FERC ¶ 61,159

[138] E.g., measurements from a fault recorder, PQ meter, recording device, or device log

[139] 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 as it does not provide active power).

**Table 3.4: ISO-NE Distributed Energy Resources as of 01/01/2018**

| DER Category[139] | Settlement-Only Resource Nameplate Capacity [MW] | Demand Resource (DR) Maximum Capacity [MW] | Total DER Capacity [MW] |
|---|---|---|---|
| Solar PV Generation not participating in the wholesale market | - | - | 1,532 |
| Total DER Capacity | 1,436 | 2,656 | 5,625 |
| Total DER Capacity/ Total Wholesale System Capability** | 4.1% | 7.5% | 15.9% |

* To avoid double counting, demand response capacity reported here excludes any BTM Distributed Generation (DG) capacity located at facilities providing demand response. Registered demand response capacity as of January 2018 is 684 MW.
** System operable capacity (seasonal claimed capability) plus settlement-only resource and demand response capacity as of January 2018 is 35,406 MW.

## Dynamic Model Verification for Multiple Generator Records at the T-D Interface

Modeling of an aggregation of DERs amidst load and at the head of the feeder, will be conducted similarly to verifying just one aggregate at the head of the feeder, with the same concerns discussed for steady-state verification.[140] Detailed in **Figure 3.2** and **Figure 3.3** is a complex set of graphs that represent R-DERs and U-DERs, along with load, connected to a 230/44/28 kV distribution substation, and the response to an electrically close 115 kV three phase fault.[141]

Under the 115 kV system three-phase fault outside the station, the entire 230 kV station sees the voltage profile,[142] which details a roughly 15–20% voltage sag at the time of the fault. The station has one 230/44 kV step-down transformer (T3). The 44 kV feeders supplied by T3 connect four solar farms (Solar 1 to Solar 4 in **Figure 3.2**) and one major load customer at the end of the feeder ("Load" in **Figure 3.2**). The station also has two 230/28 kV step-down transformers (T1 and T2). Two solar farms (Solar 5 and Solar 6) and other loads with BTM generation are connected to the 28 kV feeders. The voltage of the 230 kV substation returns to normal after the fault; however, the current contributions across the distribution transformers change from what was expected. At the 44 kV yard all four solar installations rode through the fault with increased current injection during fault. All load also rode through the event. Aggregated current at T3 shows total current unchanged after the fault but with a big increase during the fault. This is different from fault signatures in traditional load supply stations, which are characterized by reduced current during fault when the fault is outside of the station (i.e., upstream of the recording devices). This difference arises due to the fault current injected by the solar installations during the fault that passed through T3. Aggregated DER models should capture such increased current injection under external faults, and measurements like **Figure 3.3** assist in verifying those parameters.

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 DERs. This demonstrates that the pickup of the load was across the T1/T2 transformers. Based upon **Figure 3.2** and **Figure 3.3** 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 TP decides to model this complex distribution substation into the planning

[140] 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 for more information.
[141] Note that it is only necessary to collect multiple U-DER locations when more than a single U-DER installation is modeled at the substation in the aggregation.
[142] Left top corner of the figure

models. In summary, with metering at each U-DER,[143] large load, and station terminals, this example has enough information for verification of the complex aggregate model that represents these DERs. Primarily, the verification process would show a need to parameterize T1 and T2 to reflect the reduction of DERs from Solar 5 and Solar 6, while having T1's DER representation parameterized such that this reduction is not present.[144]

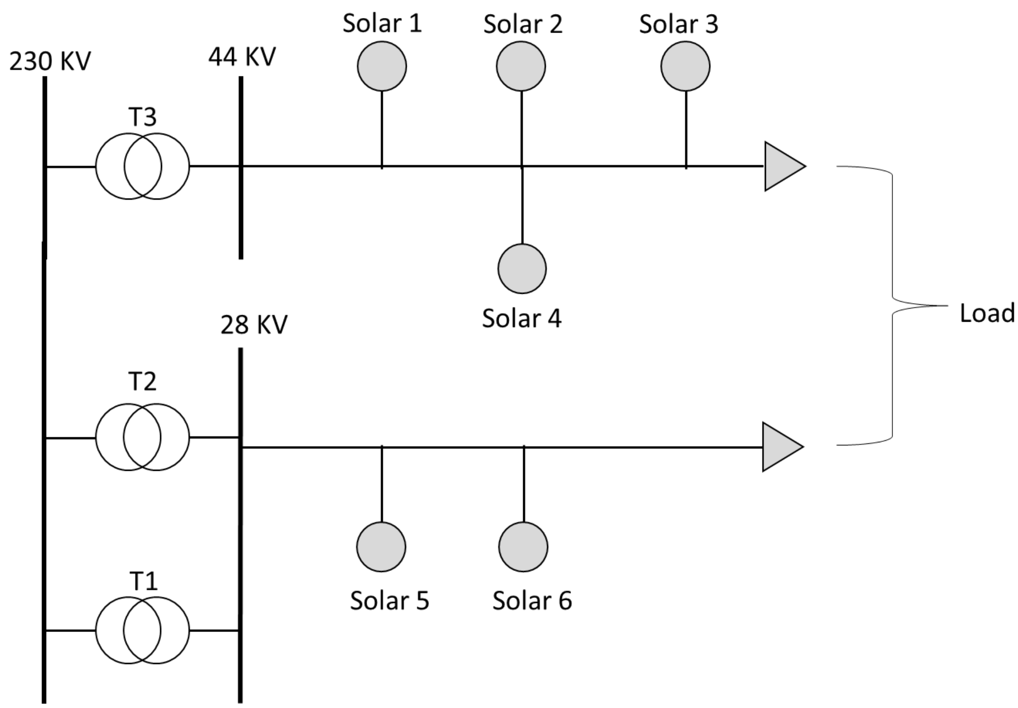


**Figure 3.2: 230-44-28 kV Substation High Level Representation**

[143] Note that some required monitoring at the end of the feeder.

[144] Again, it is important to note that engineering judgement could also be used if the load measurement was unavailable. Namely, if the TP or PC has a reasonable assumption that load would not trip out for this fault, any increase of transformer current can be associated with a trip or reduction of DER.

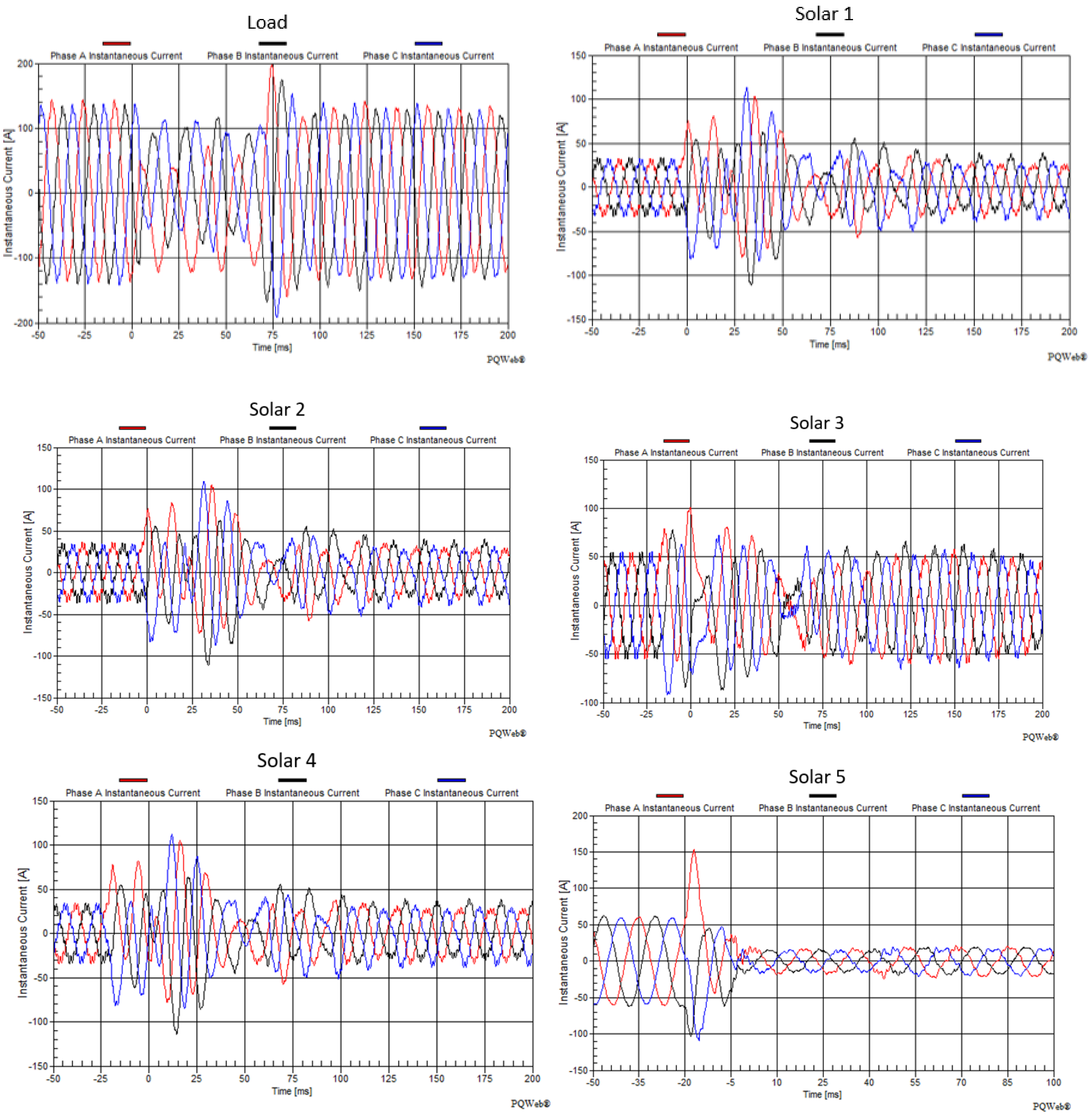


**Figure 3.3: 230-44-28 kV Substation Response to a 115 kV Three Phase Fault**

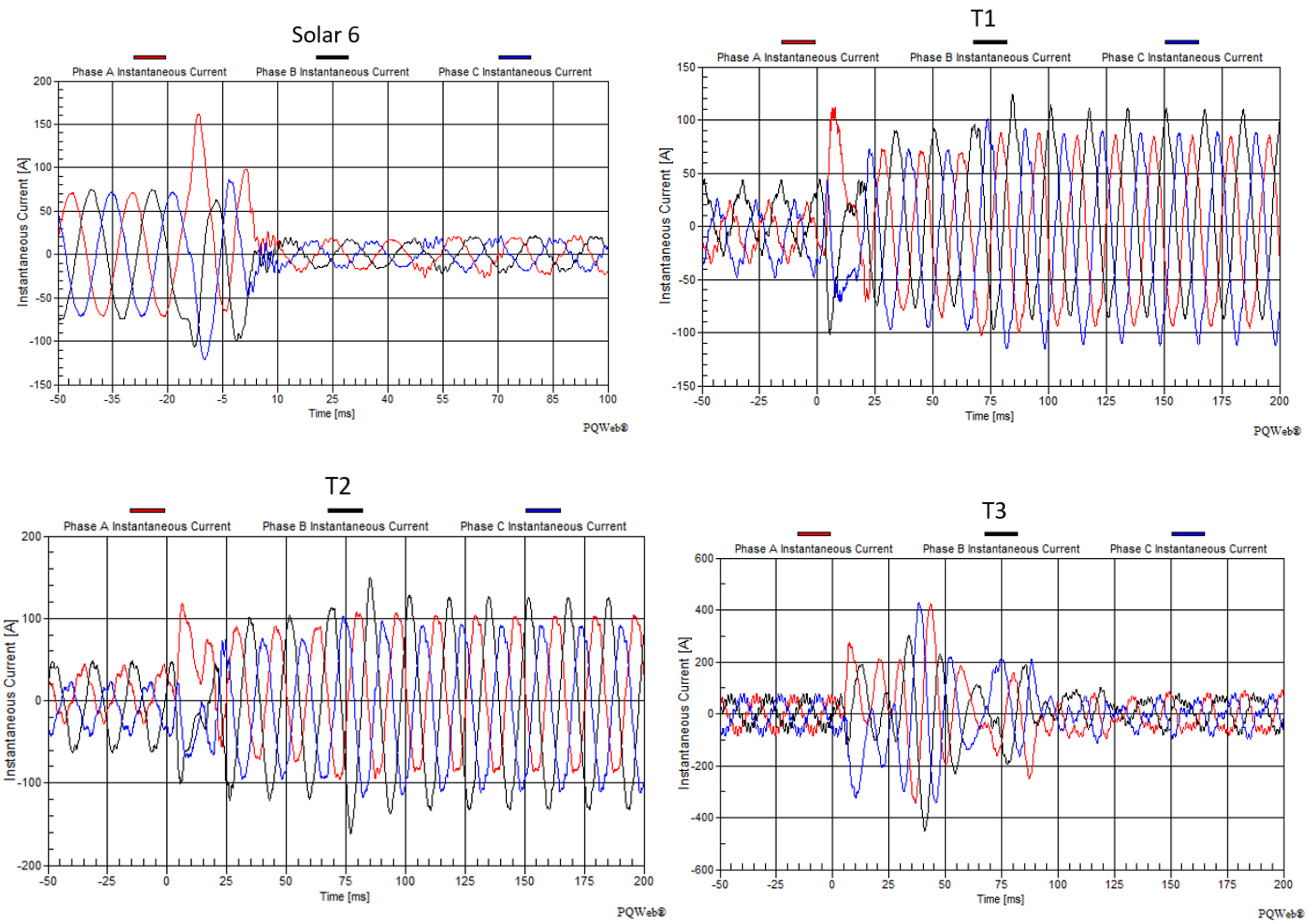


**Figure 3.3: 230-44-28 kV Substation Response to a 115 kV Three Phase Fault**

## Dynamics of Aggregate DER Models

Though similar to the process for individual DER models, there are a few more nuances in the procedure for multiple generator models. As the **Recommended DER Modeling Framework** shows, DERs on the feeder will impact substation level measurements taken. This raises a challenge where the number of independent variables in the 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 3.4** describes the overall dynamic representation of U-DER-modeled DERs and R-DER-modeled DERs with respect to the T–D interface, and 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 toward each model as seen in **Table 3.5**.

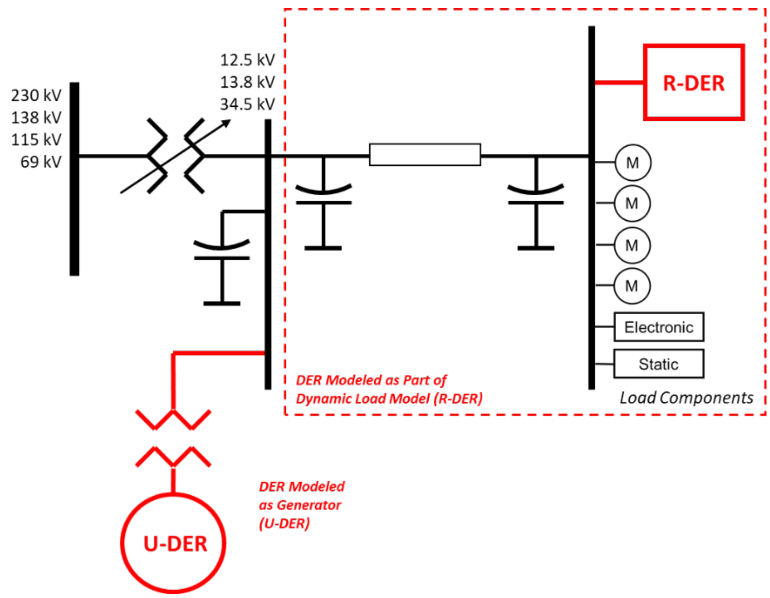


**Figure 3.4: Aggregate DER Dynamic Representation Topology Overview**

| **Table 3.5: 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 |
| 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 DER amidst load | Substation level to calculated mean | Resistive loss and voltage drop | Feeder, voltage drop / rise parameters |

Most notably, the last two rows of the table detail a way to help separate tripping parameters and voltage profiles seen at the terminals of U-DER and R-DER; however, these parameters may be the same for instances where U-DER installations are closer to the centroid of the feeder (i.e., more in the center of load). Should any of the above data be restricted or unavailable, following the engineering judgments in the *Reliability Guideline: DER_A Parameterization for Aggregate DER*[145] will assist in identifying the parameters to adjust based on inverter vintages. Further, the data answers in **Table 3.5** are not a substitution 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 3.5**, the TP or PC can make informed tuning decisions when verifying their models. In terms of the DER_A model referenced in the reliability guideline above, there are some parameters that should not be tuned, and the guideline makes those explicit. In general, each model will have a set of parameters that are more appropriate to adjust to align with gathered measurements or answers to questions regarding installed equipment. Engineering judgement and the latest available guidance on specific models should be used to identify parameters to tune in the model.

[145] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_ModelingMerge_Responses_clean.pdf

## Initial Mix of U-DERs and R-DERs

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

# Parameter Sensitivity Analysis

As with most models, certain parameters in the DER_A model may impact the model output at the margins depending on the original parameterization. Trajectory sensitivity analysis (TSA), a type of sensitivity analysis varying the parameters of a model, quantifies the sensitivity of the dynamic response of a model to small changes in their parameters.[146] While TSA is commonly implemented differently across multiple organizations, certain software packages include a basic implementation. Among them are MATLAB Sensitivity Analysis Toolbox[147] and MATLAB Simulink. TSA analysis with respect to verifying DER_A dynamic model parameters can be found in **Appendix D**.

TSA is one of many methods for TPs and PCs to gain understanding of the sensitivity of the dynamic model regarding small changes in model parameters; however, this is not a required step in model verification nor a required activity for tuning dynamic models. Furthermore, 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 is 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 needed for a TP to verify the aggregate DER dynamic model. However, performing the analysis can aid TPs in tuning their models. It is recommended that multiple parameter sets for DER models be tested against dynamic measurements when performing parameter analysis. Because of all these qualifications, use of TSA should be supervised using strong engineering judgment.

[146] Hiskens, Ian A. and M. A. Pai. "Trajectory Sensitivity Analysis of Hybrid Systems." (2000)
[147] https://www.mathworks.com/help/sldo/sensitivity-analysis.html

# Chapter 4: Short-Circuit Data Collection Requirements

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

## Applications of Short-Circuit Studies

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

- **Breaker Duty Assessments:** In breaker duty assessments, all resources are on-line for the worst-case assumption to ensure that BPS breakers will always be rated sufficiently to clear BPS fault events. This assumption has been used extensively in the past and will likely continue to be used in the future for these types of studies. In any system, the "significance"[148] of aggregate DER fault current will need to be considered by the engineer performing the studies. In areas where breakers are very close to their duty rating, aggregate DER contributions may be warranted (particularly for localized issues).
- **Setting Protective Relays:** Protective relay setting analyses study "all lines in-service" conditions as well as credible outage conditions that can affect the fault current characteristics of the local network. Alternate contingency events are selected and studied to ensure correct relay operation for a wide range of system configurations. In this case, the focus is not on equipment ratings; rather, it is on secure protection system operation. As the penetration of BPS-connected inverter-based resources as well as DERs continue to increase, BPS fault current impacts will become more significant and will need to be considered. This will likely be on a case-by-case basis in the near-term; however, this type of aggregate DER modeling data will likely be needed on a more regular basis in the future. Not fully modeling potential impacts to BPS fault current can have an adverse impact on setting protective relays.

In either type of study, it is important for TOs and TPs to establish data collection practices early to ensure sufficient data can be collected for performing accurate short-circuit studies. BPS equipment integrity and public safety are of utmost importance, and these studies rely on sufficient data to conduct them.

## Potential Future Conditions for DER Data and Short-Circuit Studies

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

> **Key Takeaway:**
> There are likely some cases where aggregate DER and load data can improve short-circuit studies, particularly for local breaker-duty studies. TPs, PCs, and TOs should establish clear short-circuit data collection practices when DER become impactful to these studies.

[148] "Significance" is used loosely and generally in this discussion but becomes increasingly important under high-penetration DER conditions.

| Table 4.1: Potential Future Conditions for DER Data Collection for Short-Circuit Studies | |
|---|---|
| **#** | **Potential Future Conditions and Considerations** |
| 1 | **Condition:** BPS-connected synchronous generators dominate, and DERs are not prevalent. |
| | **Consideration:** This may be the status quo for some entities. BPS-connected synchronous generators provide significant fault current, and aggregate DERs and end-use loads are typically not modeled because the majority of fault current comes from synchronous machines. |
| 2 | **Condition:** Resource mix consists of both BPS-connected inverter-based and synchronous generators, and DERs are not prevalent. |
| | **Consideration:** This is likely the status quo for many entities with growing penetrations of BPS-connected wind and solar PV but fairly low penetrations of DERs. BPS fault currents are decreasing due to the BPS-connected inverter-based resources.[149] Aggregate DERs and end-use loads are generally not modeled in short-circuit studies because the majority of fault current still comes from the BPS (mainly synchronous generators). |
| 3 | **Condition:** BPS resource mix consists of both synchronous and inverter-based resources, and DERs are becoming increasingly prevalent. |
| | **Consideration:** Some areas are experiencing this condition today (e.g., CAISO, ISO-NE). The growth of DERs in conjunction with increasing BPS-connected inverter-based resources is leading to a high overall inverter-based system. Increased BPS-connected inverter-based resources are still affecting fault characteristics[150] on the BPS. Legacy DERs are likely not providing fault current due to the use of tripping and momentary cessation for large disturbances, and there likely has been a lack of interconnection requirements to specify behavior for DERs during fault events. Inverter-based DERs providing fault current, where applicable, may have an impact on localized breaker duty studies and may need to be considered for setting protective relays. On a broader scale, synchronous generators dominate BPS fault current; the impedance between DERs and the BPS fault is so large that DER fault current contribution to the BPS is relatively low. Therefore, TPs and PCs will need to explore this on a case-by-case basis but should ensure the ability to collect aggregate DER data. |
| 4 | **Condition:** DERs can provide the majority of energy to end-use customers during certain instances; these conditions are likely coupled with increasing BPS-connected inverter-based resources and limited on-line synchronous generators. |
| | **Consideration:** Few, if any, areas of the North American BPS experience situations like this today; however, this scenario may be more likely in the future (even within the planning horizon). Lack of on-line synchronous generators causes low fault current magnitudes. DER interconnection requirements for new-vintage DERs may allow for momentary cessation as a default setting (i.e., IEEE 1547-2018). Existing and future installations of DERs may not provide fault current unless momentary cessation is prohibited by local requirements.[151] Where DERs are providing fault current, inverter-based DERs can only provide a limited magnitude of current and their contribution will be primarily for nearby local faults; the impedance between the DERs and the BPS fault location cause their contribution to be low. BPS protective relaying could experience issues under these types of scenarios either due to very low fault current levels or unknown/unstudied fault current behavior (e.g., phase relationship).[152] Solutions may be needed to maintain acceptable levels of fault current (e.g., synchronous condensers). Some synchronous generation will likely remain on-line for the foreseeable future (i.e., hydro generators), providing a suitable amount of fault current in those areas. However, as the primary source of generation (and possibly fault current) in this scenario, aggregate DERs may need to be modeled in short-circuit studies. Aggregate representation of DERs is likely suitable as long as any significant differences in fault current contribution is differentiated. TPs and PCs will need to assess the potential for this scenario and determine whether they should proactively collect aggregate DER data for short-circuit modeling. |

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

[150] Decreasing fault current magnitude and the uncertain phase angle relationship between voltages and currents from inverter-based resources

[151] This will need to be analyzed closely and coordinated between distribution and transmission planning and protection engineers.

[152] This would be caused both by BPS-connected inverter-based resources as well as the DERs.

## Differentiating Inverter-Based DERs

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

### Example Impact of Aggregate DERs on BPS Fault Characteristic

Whether or not a specific DER (i.e., U-DERs) or aggregate amount of DERs (i.e., R-DERs as well as U-DERs) have a significant[153] impact on the BPS will need to be determined by the TP and PC performing such studies. During SPIDERWG discussions, Southern California Edison provided a rough rule-of-thumb for DER impacts to be the following values:[154]

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

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

## Considering Short-Circuit Response from DERs and Loads

Inverter-based DERs configured to provide fault current are limited to around 1.1 pu maximum fault current due to the power electronics interface of the inverter. On the other hand, direct-connected motor loads will dynamically respond during and immediately after the fault and affect overall fault current contribution along the feeder. This is particularly true for R-DERs spread throughout the feeder; however, fault current from U-DERs located at or near the head of the feeder may provide little fault current through the T-D interface. Therefore, short-circuit characteristics of end-use loads will need to be taken into account when considering DER short-circuit contributions.

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

[153] The term "significant" is used loosely and generally in this discussion but becomes increasingly important under higher penetrations of DERs.
[154] This assumes a mix of R-DER and U-DER along the feeder and assumes a maximum fault current from DERs of 1.1-1.2 pu based on available inverter manufacturer data.

### Verification of Short-Circuit Response from DERs and Loads

As the verification of short-circuit response from DERs and load requires a fault to occur and sensitive equipment to measure the contributions across the distribution system, the SPIDERWG does not recommend a widespread initiative to verify short-circuit parameters.[155] Any testing in such a manner should be done on an ad hoc basis with solid engineering judgement and specialized equipment in place to ensure the testing of the system does not need to be repeated. SPIDERWG does recommend communication of known short-circuit parameters from distribution entities to transmission entities to identify portions of the bulk system that may have a short-circuit coordination concern. TPs, PCs, and DPs should also verify instances where distribution fuse-based protection would warrant the fault current contribution of DERs and load in transmission-level models.

## Aggregate DER Data for Short-Circuit Studies

In cases where DER data may be necessary for short-circuit studies, the TP and PC will need to establish requirements per MOD-032-1 Requirement R1 around what types of short-circuit modeling data need to be provided by the DP. These requirements should be as clear and concise as possible to help facilitate this data transfer. It is likely that many TPs and PCs fall into either Categories 2 or 3 of **Table 4.1** today. Where DER data may be needed for forward-looking short-circuit studies, the following information may be useful regarding aggregate[156] DERs:[157]

- Continuous MVA rating of aggregate DERs
- Estimated vintage of IEEE 1547-2018 and settings applicable for DER tripping and momentary cessation (i.e., would the DER trip or cease current injection for fault events)
- Assumed effective fault current contribution at a specific time frame(s)[158] during the fault
- Assumed phase angle relationship between voltages and currents

### Example where DER Modeling Needed for Short-Circuit Studies

One example of where U-DER data may be needed is local breaker duty short-circuit analyses. Consider **Figure 4.1**, which shows a 230/69 kV network with a hypothetical yet possible situation where breaker underrating could happen. At the MK-69 bus, before the addition of DER #1 (20 MW) and DER #2 (20 MW), the breaker at MK-69 (shown in red) connecting the circuit to GY-69 is at 99.4% of interrupting duty when a fault is applied on the MK-69–GY-69 circuit (shown in **Figure 4.1** as well). If the DER fault current contribution were ignored, then short-circuit studies would remain unchanged since the contribution from DERs would not be modeled. However, if the 40 MW nameplate capacity of DERs is modeled to provide 1.1 pu fault current, the breaker could be underrated as the interrupting fault duty jumps to 101.1% and exceeds the 100% rating of the BPS element. These effects may be observed locally today across many parts of the BPS but may also become more prominent as the amount of DERs continues to increase (or if the fault current contribution is much higher from a synchronous DER).

[155] Such an initiative would entail a high cost to measurement equipment as well as require intentionally faulting the electric system, most likely creating disruptions and interruptions to load.
[156] Again, this is likely on a T-D transformer basis, per TP and PC data reporting requirements.
[157] Based on minimum requirements for modeling voltage-controlled current sources in short-circuit programs
[158] These may include sub-transient, transient, and other applicable time frames based on TP and PC modeling and study techniques.

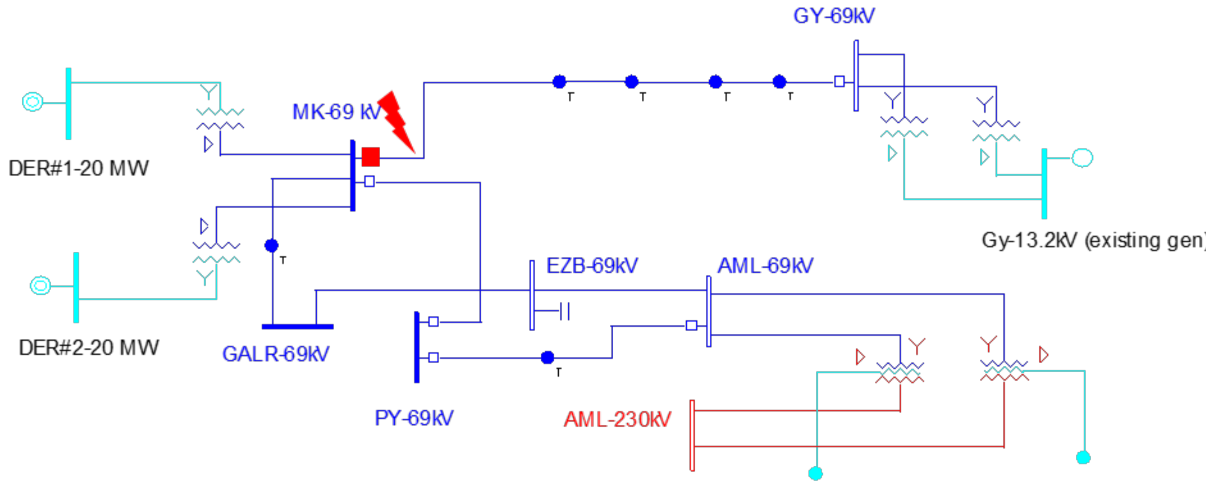


**Figure 4.1: Example Network for Breaker Underrating Example**

# Chapter 5: GMD Data Collection Requirements

NERC TPL-007-3[159] requires TPs, PCs, TOs, and Generator Owners (GO) owning facilities that include power transformers with a high-side, wye-grounded winding with terminal voltage greater than 200 kV to perform GMD vulnerability analysis[160]. The GMD vulnerability assessment is a documented evaluation of potential susceptibility to voltage collapse, cascading, and localized damage to equipment due to GMD events.[161]

During a GMD event, quasi-dc GICs flow through transmission circuits and return to the Earth by grounded-wye transformers and series windings of autotransformers that provide a dc path between different voltage levels. DC current flow through transformers produces harmonic currents that can increase transformer reactive power consumption and may cause hot-spot heating that potentially leads to premature transformer loss of life or failure. Furthermore, harmonic currents spreading through the power system can cause BPS elements to trip and may be a potential susceptibility for aggregate DER tripping.[162]

In performing GMD vulnerability assessments, TPs and PCs use a dc-equivalent system model (GIC system model) for determining GIC levels and a steady-state power flow model for assessing voltage collapse risks. Current GMD vulnerability assessment techniques, per TPL-007-3, do not call for modeling the distribution system or including DER data.[163] Typically, only higher voltage BPS elements are represented in these simulations because long transmission circuits with low impedance generally produce the highest levels of GICs. Furthermore, delta transformer windings block GICs from flowing since they do not create a return path for GICs to flow. Many T-D transformers are delta-wye (grounded on the distribution side), so GICs could only flow on the distribution side. However, distribution circuits are relatively short and have high impedance, so GIC flow at the distribution level will be insignificant with respect to BPS impacts. Hence, distribution-level circuits are not included in the dc-equivalent system model (GIC system model).

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

Based on these findings, there is currently no need to model the distribution system, end-use loads, or aggregate DERs for the purposes of vulnerability assessments in TPL-007-3. However, as the penetration of DERs continues to increase, this assumption may need to be revisited in the future. The vulnerability of DERs to GMD-caused severe voltage distortion remains an issue for industry to explore in more detail.

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159 https://nerc.com/pa/Stand/Reliability%20Standards/TPL-007-3.pdf

160 The 200 kV and above threshold was compared to the impact of ignoring the 115 kV portion of the transmission system and findings were that impact to GIC current was negligible. See here: https://www.nerc.com/pa/Stand/Project201303GeomagneticDisturbanceMitigation/ApplicableNetwork_clean.pdf

161 See NERC's *Glossary of Terms* used in Reliability Standards: https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

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

163 NERC *Application Guide for Computing Geomagnetically-Induced Current in the Bulk-Power System*, December 2013: https://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf, and
NERC *GMD Planning Guide*, December 2013: https://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf

# Chapter 6: EMT Data Collection Requirements

As the penetration of BPS-connected inverter-based resources continues to grow, EMT modeling and simulations are becoming increasingly critical for ensuring reliable operation of the BPS. Entities are developing interconnection requirements for BPS-connected inverter-based resources to ensure that modeling information is available to perform EMT simulations when needed.[164] As the DER penetration continues to grow, there may be situations where studying reliable operation of the BPS, including networked sub-transmission systems, will require modeling DERs.[165] If industry is moving toward performing EMT simulations for BPS-connected plants (for example, on the order of 50 MW) because of known reliability issues, it warrants similar EMT simulations to be performed for pockets of high penetrations of DERs as well (for example, a small geographic area of 50–100 MW of DERs). This chapter describes situations where representing DERs in EMT models may be needed by the TP and PC and the steps that can be taken to help facilitate development of these models in coordination with the DP.

## DER Modeling Needs for TPs and PCs

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

- High penetration pockets of inverter-based resources, particularly when DERs replace or displace synchronous generation in the local area. The lack of synchronous resources presents challenges related to synchronous inertia and low short-circuit strength conditions. As these pockets experience increasing penetrations of DERs, potential reliability risks may arise that require EMT simulations to identify.
- Ride-through performance for DERs (and BPS-connected inverter-based resources). This becomes critical during severe voltage excursions in pockets of low short-circuit strength and often requires EMT simulations that represent the specific phase-based protection aspects and inner control loops of inverter controls.
- Analysis of voltage control performance and coordination of voltage control settings across many DERs and the BPS. Areas with high penetration of DERs may need to rely on dynamic reactive support on the BPS and may see greater variability of voltages at the distribution level. This will need to be coordinated, and EMT simulations are more effective at identifying issues than fundamental-frequency, positive sequence, or phasor simulations.
- Pockets of high penetrations of inverters. These can control interactions between neighboring facilities or with the grid. In addition, these pockets may present control stability issues for inverter-based resources that require attention for aspects of large disturbance behavior, such as active and reactive power recovery and oscillations. When DERs represent a substantial amount of generation in a localized area, these issues may arise and could impact the BPS.
- Selection of control modes, such as momentary cessation and other ride-through performance, and reliable operation of the overall area or region (including parts of the BPS). These may be necessary under high DER penetration conditions.

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164 https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_IBR_Interconnection_Requirements_Improvements.pdf

165 https://www.nerc.com/comm/PC/System%20Planning%20Impacts%20from%20Distributed%20Energy%20Re/Studies%20-%20SPIDERWG%20Bulk%20DG%20penetration%20study%20-%20Marszalkowski,%20Isaacs.pdf

There is no clear threshold for when EMT simulations are needed in any of the situations described above.[166] TPs and PCs have developed various metrics to identify potential conditions, specifically for BPS-connected inverter-based resources, that warrant closer attention through EMT simulation techniques.[167]

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

EMT models are detailed representations of system elements used to identify a wide range of potential issues, as mentioned above. However, representing end-use loads or aggregate DERs, in many cases, requires that some assumptions and estimations be applied. While use of generic models for EMT simulations is typically discouraged for BPS-connected resources, the data for creating EMT models (or the EMT models themselves) may not be available for many types of DERs. For cases where the TP and PC have determined that an EMT study involving aggregate DERs may be needed to ensure reliability of the BPS,[168] the following recommendations are made:

- **R-DER:** Small, retail-scale DERs across the distribution system (e.g., rooftop solar PV) will most likely not have DER models or information available, and this level of detail is not needed for a BPS EMT simulation. Rather, generic EMT models can be used to represent the aggregate amount of DERs at locations, similar to how steady-state power flow and fundamental-frequency positive sequence simulations are performed. For the most part, the information needed to formulate an EMT model of aggregate DERs will mirror the information needed for fundamental-frequency, positive sequence dynamic models (i.e., steady-state and dynamic transient models in **Chapter 1** and **Chapter 2**), including the following:
  - Type of DER and vintage of IEEE 1547
  - Disturbance ride-through behavior including use of momentary cessation
  - Voltage, frequency, phase angle, and ROCOF trip thresholds
  - Dynamic and steady-state voltage control performance expectations
  - Reasonable representation of the per-phase nature of DER functions, to the ability of the model
- **U-DER:** Some entities have implemented the same modeling requirements for larger inverter-based U-DERs as for BPS-connected inverter-based resources; namely, that an EMT model may be requested from the TP or PC and will need to be supplied by the DER owner in coordination with the manufacturer, to the extent possible. This is typically applicable only for U-DER facilities greater than 1 MVA in capacity. For substations with multiple inverter manufacturers, the TP and PC may aggregate these models into distinct U-DERs for the more predominant inverter types. On the other hand, other entities may deem that generic models may be suitable for U-DERs as well, and the information described above could also apply for developing EMT models for U-DERs.
- **Load Models:** In situations where detailed DER models are being provided or created for the purposes of EMT studies, it is also important to accurately capture the expected behavior of aggregate amounts of end-use loads. The performance of the end-use loads in combination with DERs will have an impact on the distribution system and BPS performance, and these should be accounted for in some way. The TP and PC will need to coordinate with the DP and/or TO to provide this load information in addition to the DER information found in the above bullet points.

Industry is still grappling with the growing need for EMT simulations in many areas, and new findings and recommendations will continually be developed. It is clear, however, that EMT simulations may be needed to

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[166] The NERC Inverter-Based Resource Performance Subcommittee is also working on a reliability guideline on EMT studies. It is slated to be released in 2023 and will be published under the RSTC here: https://www.nerc.com/comm/Pages/Reliability-and-Security-Guidelines.aspx

[167] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Item_4a._Integrating%20_Inverter-Based_Resources_into_Low_Short_Circuit_Strength_Systems_-_2017-11-08-FINAL.pdf

[168] Independently of the BPS study, a DP that needs to perform EMT analysis on its distribution system may require similar, if not more detailed, information than is provided in the list.

appropriately identify specific reliability issues in high DER penetration pockets; [169] therefore, the TP and PC should coordinate with the DP, equipment manufacturers, or other external entities to gather EMT modeling information to the extent possible, when needed. In areas where there is not a DP across the T-D interface, the TP may need to revise their interconnection agreements to begin this collaboration.[170] A transmission study to investigate high DER penetration pockets will require a distribution EMT study to ensure that the equivalent distribution systems in the pocket are representative. However, a transmission EMT study that incorporates the impact of the T-D interface does not have the same limitations. The modeling practices and level of detail will differ between both studies as the reliability issue to be studied is different. In both cases, increasing coordination among the transmission and distribution entities will highlight the information needed to capture the issue to be studied and determine the models to be developed that represent the DER and load behind the T-D interface.

[169] SPIDERWG has provided a technical report that highlights the various aspects for these types of simulations, available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Beyond_Positive_Sequence_Technical_Report.pdf

[170] There may be other venues to start the collaboration than a revision to the interconnection agreements. This underscores a higher need for collaboration in this area.

# Appendix A: References For Further Reading


- NERC, “Connection Modeling and Reliability Considerations,” Atlanta, GA, February 2017.
- NERC, “Technical Brief on Data Collection Recommendations for Distributed Energy Resources,” Atlanta, GA, March 2018.
- NERC, “Reliability Guideline: Modeling Distributed Energy Resources in Dynamic Load Models,” Atlanta, GA, December 2016.
- NERC, “Reliability Guideline: Distributed Energy Resource Modeling,” Atlanta, GA, September 2017.
- NERC, “Reliability Guideline: Parameterization of the DER_A Model,” Atlanta, GA, September 2019.
- P. Pourbeik, “Proposal for DER_A Model,” WECC Renewable Energy Modeling Task Force, Salt Lake City, UT, September 2018.
- NERC, “Reliability Guideline: Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources,” Atlanta, GA, September 2019.
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- NERC, “TPL-001-4 – Transmission System Planning Performance Requirements,” Atlanta, GA, October 2014.
- NERC, “TPL-007-3 – Transmission System Planned Performance for Geomagnetic Disturbance Events,” Atlanta, GA, November 2018.
- NERC, “Reliability Guideline: Integrating Inverter-Based Resources into Low Short Circuit Strength Systems,” Atlanta, GA, December 2017.
- EPRI, “Assessment Guide: Geomagnetic Disturbance Harmonic Impacts and Asset Withstand Capabilities,” 3002017707, Palo Alto, CA, December 2019.
- IEEE, “1547-2018 – IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces,” April 2018.
- IEEE, “1547a-2014 – IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems – Amendment 1,” May 2014.
- IEEE, “1547-2003 – IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems,” July 2003.
- Ofgem, “Technical Report on the Events of 9 August 2019,” London, United Kingdom, September 2019.

# Appendix B: Data Collection for DER Energy Storage

Collecting data for DER energy storage is similar to collecting data for DER generating resources. However, considerations should be made when developing requirements for collecting DER data to ensure clarity when energy storage is included in planning assessments. This appendix describes some of the high-level considerations that should be made and also describes specific data points unique to energy storage from a data collection standpoint. While there are many types of energy storage technologies available today, this appendix focuses mainly on inverter-based battery energy storage since it is the most prominent form of DER expected in the foreseeable future and is widely observed in DER interconnection queues today. Existing large, synchronous DERs may need to be modeled explicitly based on TP and PC modeling practices, and the TP and PC should have these considerations listed in any modeling requirements. Note that electric vehicles today are likely modeled as part of the load since most existing electric vehicles do not provide storage capability, and demand response actions (such as reduction of heat pump loads) are also not generally modeled as energy storage in planning models. Lastly, there are different ways to model energy storage DERs—as part of the composite load model, as a standalone resource, or lumped with other forms of DERs. This guideline focuses on data collection necessary for the TP and PC to make appropriate modeling decisions based on their own practices.

## Considerations for Steady-State Modeling

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

- **Location:** TPs and PCs need to know the general location (at least mapped to a T-D transformer) of energy storage batteries so they can be modeled appropriately in planning base cases in conjunction with other DERs and end-use loads. Separating DER generation and energy storage for collecting accurate DER data from the DP in coordination with any other state-level agency or regulatory body is a prudent step for effectively developing base cases based on TP and PC practices.
- **DER Type (or aggregate type):** As stated, differentiating DER generators, DER energy storage, and hybrid facilities is necessary for aggregate modeling of DERs in the future.
- **Transformer Information:** If the energy storage DER is represented as a U-DER, a generator step-up transformer may be explicitly modeled by the TP and PC based on their modeling practices.[171] In this case, transformer information may be needed by the TP and PC for modeling the energy storage DER facility. Appropriate reactive capability at the U-DER point of interconnection should be modeled regardless of modeling practice.
- **Historical or expected DER output profiles:** The output profiles for energy storage DERs are likely much different than for DER generation, such as synchronous or solar PV DERs. As such, the TP and PC will need to determine a suitable assumption for output profiles for each to create planning base cases. Information will be needed on energy storage DER output profiles and questions for consideration include, but are not limited to, the following:
  - What percentage of energy storage DERs are participating in wholesale markets, and can the markets in which they are participating provide any useful information in terms of how the energy storage DERs may be dispatched?

[171] These practices may include explicit modeling of the plant main power transformer and equivalent representation of individual pad-mounted transformers within the U-DER facility, or it may be simplified to an equivalent representation of transformations. The TP and PC should have modeling requirements that clarify this point.

  - What percentage of energy storage DERs are operating based on retail signals, such as time-of-use charges or other third-party signals that drive charging and discharging, at specific hours of the day? Most commonly, the assumption is made that energy storage DERs will charge during light load conditions and discharge during peak loading conditions; however, some entities have experienced energy storage charging patterns that do not conform to these basic assumptions. Therefore, the DP will need to coordinate with the TP, PC, and any other state-level agency or regulatory body to determine how these patterns could affect transmission planning processes and practices.

- **DER Status:** It is not likely that additional considerations will be needed for energy storage DERs related to status (on-line versus off-line). However, TPs and PCs will need to consider whether the aggregate amount of energy storage DER is charging or discharging.
- **Maximum DER active power capacity (Pmax):** As mentioned, differentiating the amount (capacity) of energy storage DERs will enable the TP and PC to model these resources, as needed. It is not likely that additional information would be needed for energy storage DERs.
- **Minimum DER active power capacity (Pmin):** Energy storage resources can charge (unlike DER generators), so energy storage DERs will have a modeled negative Pmin value in the base case. Therefore, separating out energy storage DERs will enable reasonable representation of Pmin values in the base case.
- **Reactive power-voltage control operating mode:** Similar to DER generators, it is important to understand any interconnection requirements and operating practices for the DERs regarding their reactive power-voltage controls. With this information, TPs and PCs can model them accordingly.
- **Maximum DER reactive power capability (Qmax and Qmin):** If energy storage DERs are providing any voltage support, these resources will need an associated Qmax and Qmin value in the base case, and the DP will need to coordinate with the TP and PC to understand appropriate assumptions.

# Considerations for Dynamics Modeling

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

- ***Typeflag*:** Explicit modeling of energy storage DER requires consideration of the *typeflag* parameter of the DER_A dynamic model. Refer to software model specifications for how to set *typeflag* to emulate an energy storage device.[172]
- ***Pmin*:** The *Pmin* will need to be modified to accommodate the capability to absorb active power (i.e., negative *Pmin*), based on the expected energy storage capacity being modeled. If the voltage-dependent current limits (absolute value, not sign) are different in charging versus discharging mode, the values of the voltage-dependent current logic (VDL) tables will need to be changed based on the operating mode assumption.
- **Frequency Response Parameters:** If the energy storage DER is providing frequency response capability in either the upward or downward directions or both, these parameters will need to be configured accordingly. This could be different than the aggregate DER generation model. For example, R-DERs may not be providing underfrequency response; however, larger energy storage DERs may be providing this capability and service to a wholesale market.
- **Frequency and Voltage Ride-Through Capability:** TPs, PCs, and DPs should consider whether any different requirements are in place for DER energy storage versus DER generation; this is not likely in most cases once

[172] Based on the specification for the DER_A dynamic model: https://www.wecc.org/Reliability/DER_A_Final_061919.pdf

the new IEEE 1547-2018 inverters become available. Consider whether the fractional reconnection (*vrfrac*) or active power ramp rate (*rrpwr*) may also be different for DER energy storage and generation.

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

# Considerations for Short-Circuit Modeling

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

# Considerations for GMD Modeling

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

# Considerations for EMT Modeling

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

# Appendix C: DER Data Provision Considerations

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

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

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

## AEMO DER Registry Case Study

A recent example of external DER data that can be useful for modeling purposes comes from the Australian Electricity Market Operator (AEMO) DER Register.[173] Under the national electricity rules that govern Australia's major electricity market across the east and south eastern states, all network service providers (NSPs) provide or update "DER generation information," defined as "standing data in relation to a small generating unit" for any DER rated below 30 MW.[174] To facilitate the collection of DER generation information, AEMO worked with NSPs, DER installers, and other stakeholders for over a year to develop a secure online DER data submission process. AEMO requires submission of DER generation information at the national metering identifier level, simultaneously leveraging the relative strengths of NSPs and installers as DER data providers. **Figure C.1** illustrates AEMO's expectation for NSPs and installers to have different types of DER data, which AEMO determined are necessary to model and plan for the impacts of aggregate DER (options are allowed as to how the data is provided into AEMO's system).[175]

173 https://www.aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-register-implementation

174 https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/NEM-Consultations/2019/DER-register/Final/DER-Register-Final-Report.pdf

175 https://www.aemo.com.au/-/media/Files/Electricity/NEM/DER/2019/DER-Register-Implementation/20191129---Introducing-DER-Register---NSW-Solar-Installer-Seminars_PDF.pdf

| Level | Data types | Expected source of data | |
|---|---|---|---|
| | | Network | Installer |
| Installation | Approved capacities, technologies and central control/protection (e.g. export limits) | ✓ | ☰ |
| | Installer licence number / ID | ☰ | ✓ |
| AC interface | Inverter or generator manufacturer, model, serial number and capacities, and numbers of installed units | ☰ | ✓ |
| | Inverter control modes and settings (e.g. volt-watt etc) | ✓ | ☰ |
| | Non-inverter generation control modes, settings and protection | ✓ | ☰ |
| | Date of commissioning | ✓ | ☰ |
| Device | Device (e.g. solar PV panels or battery) manufacturer, model and capacities, and numbers of installed units | ☰ | ✓ |

**Figure C.1: AEMO Expectations for Provision of DER Data [Source: AEMO]**

The workflow for joint submission of DER generation data from the NSP and DER installers, ultimately resulting in a DER installation certificate, is shown in **Figure C.2**. The workflow diagram emphasizes the importance of a collaborative specification for attaining DER generation information. The distinction between "as-approved" and "as-installed" information is crucial; one subset of data is likely readily available to NSPs, whereas another subset of data is likely readily available to DER installers (see **Figure C.3**).

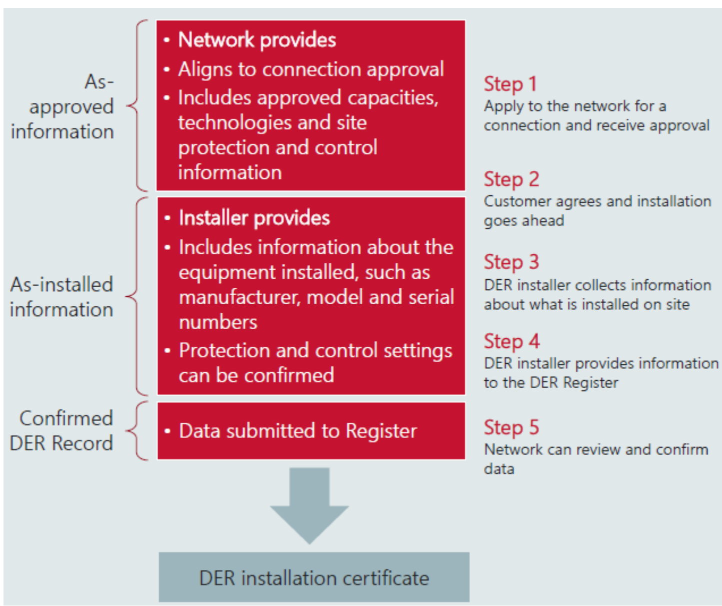


**Figure C.2: Workflow of Joint Submission of DER Generation Data [Source: AEMO]**

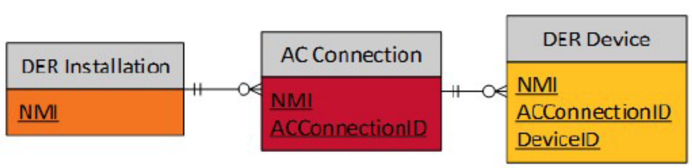


**Figure C.3: Combination of DER Data as Defined by AEMO's Data Model [Source: AEMO]**

To ensure quality of responses consistent with AEMO's data model structure, AEMO developed a series of scenarios to illustrate hypothetical DER configurations for NSPs and DER installers. **Appendix E** of AEMO's *DER Register Information Guidelines* shows the various considered scenarios.[176] The scenarios help ensure that the data requests are completed consistent with AEMO's specifications. The submission process is supported by an information collection framework that emphasizes four principles, listed below:

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

NSPs in the National Electricity Market have varying levels of sophistication when it comes to connection approvals and data collection. As a result, AEMO's DER registry system is designed with optionality to provide and validate DER data via application program interface calls directly from the NSP, AEMO's web portal, or via the smart-phone applications that many DER installers are already using to register an installation to access government subsidies. These options enable the minimum workflow change and cost for implementation for each NSP. The full design of the information collection framework and related implementation material is also publicly available.[177]

[176] https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/NEM-Consultations/2019/DER-register/Final/DER-Register-Final-Report.pdf

[177] https://www.aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-register-implementation

# Appendix D: 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 dynamic response of a 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, and the resulting parameter sensitivity indexes are summarized in **Table D.1**. Simulations were performed in PSS®E and used 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 was altered by +/- 10%; the simulated event was a three phase 500 kV fault on the line between bus number 201 and bus number 202. Parameters of the DER_A model not listed in **Table D.1** had a trajectory sensitivity of zero. 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 indicate that this calculation requires engineering judgement to determine if those parameters should 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 greatly impacts the simulation output. The parameters that are good candidates to change are those that adjust the needed section of the dynamic performance (i.e., before, during, or after the fault) in the verification process, and the parameter chosen to tune makes sense to adjust (i.e., a controller gain). To help illustrate this, consider the Trv example in **Figure D.1**; while this constant has high sensitivity, it is less likely to be altered than 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 **Figure D.2** to **Figure D.4**, respectively.

**Table D.1: Parameter Sensitivities for the DER_A model**

| Parameter | Value | Sensitivity | Description |
|---|---|---|---|
| Trv | 0.02 | High | Voltage measurement transducer time constant |
| Tiq | 0.02 | Low | Q-control time constant |
| Pmax | 1.00 | High | Maximum power limit |
| Imax | 1.20 | High | Maximum converter current |
| Vl | 0.49 | High* | Inverter voltage breakpoint for low voltage cut-out |
| Vl | 0.54 | High* | Inverter voltage breakpoint for low voltage cut-out |
| vh0 | 1.20 | High* | Inverter voltage breakpoint for high voltage cut-out |
| vh1 | 1.15 | High* | Inverter voltage breakpoint for high voltage cut-out |
| Tg | 0.02 | High | Current control time constant (to represent behavior of inner control loops) |
| Rrpwr | 2.00 | High | Ramp rate for real power increase following a fault |
| 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

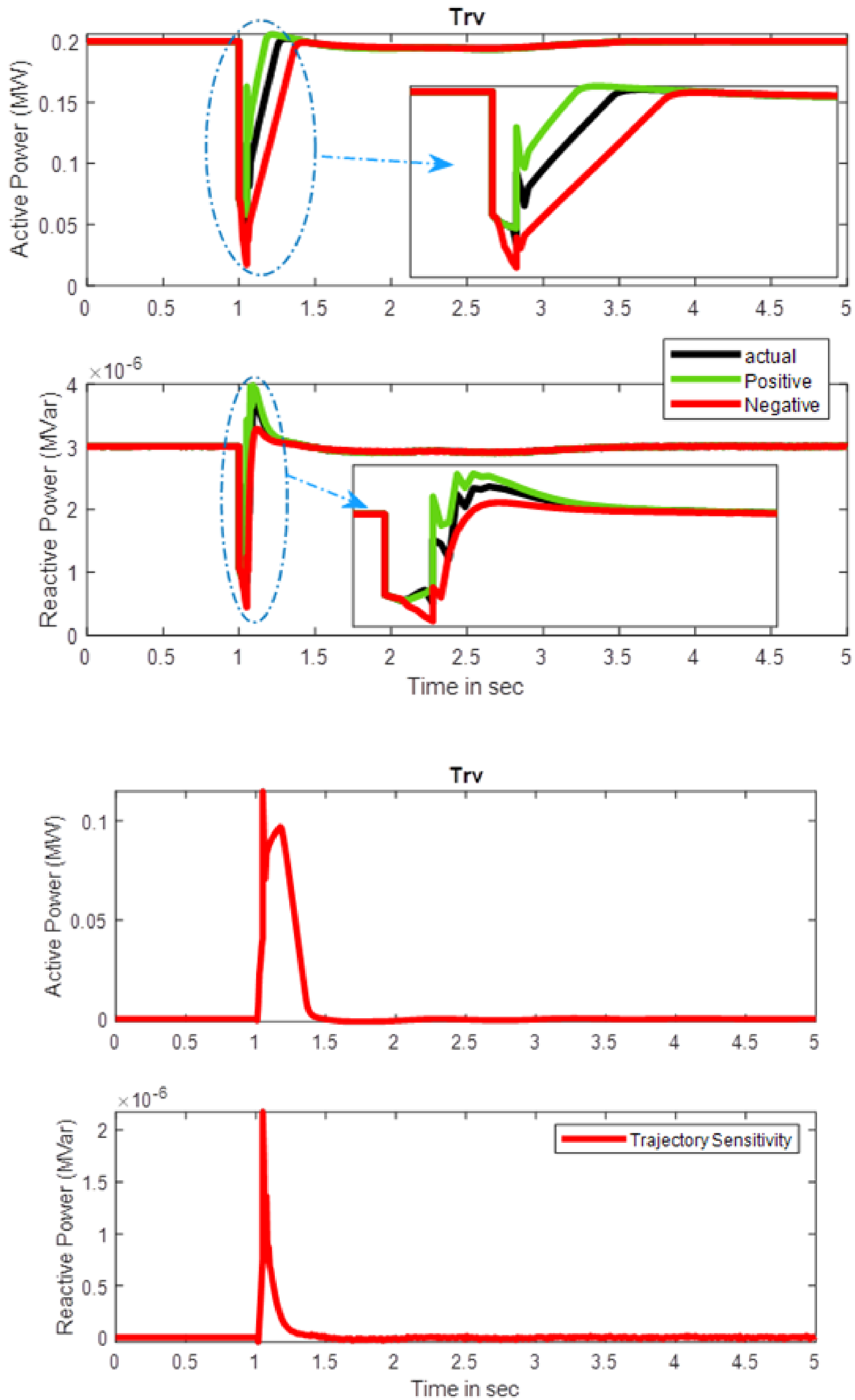


**Figure D.1: Simulation Output and the Resulting TSA Calculation on Trv[178]**

[178] The reader is cautioned that this graph and following graphs are not matching measurement data to simulation output; they are comparing a set parameter adjustment back to the original model output for the same contingency. As expected, as one increases 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 D.5 that shows the Trv constant, which demonstrates why this phenomenon exists.

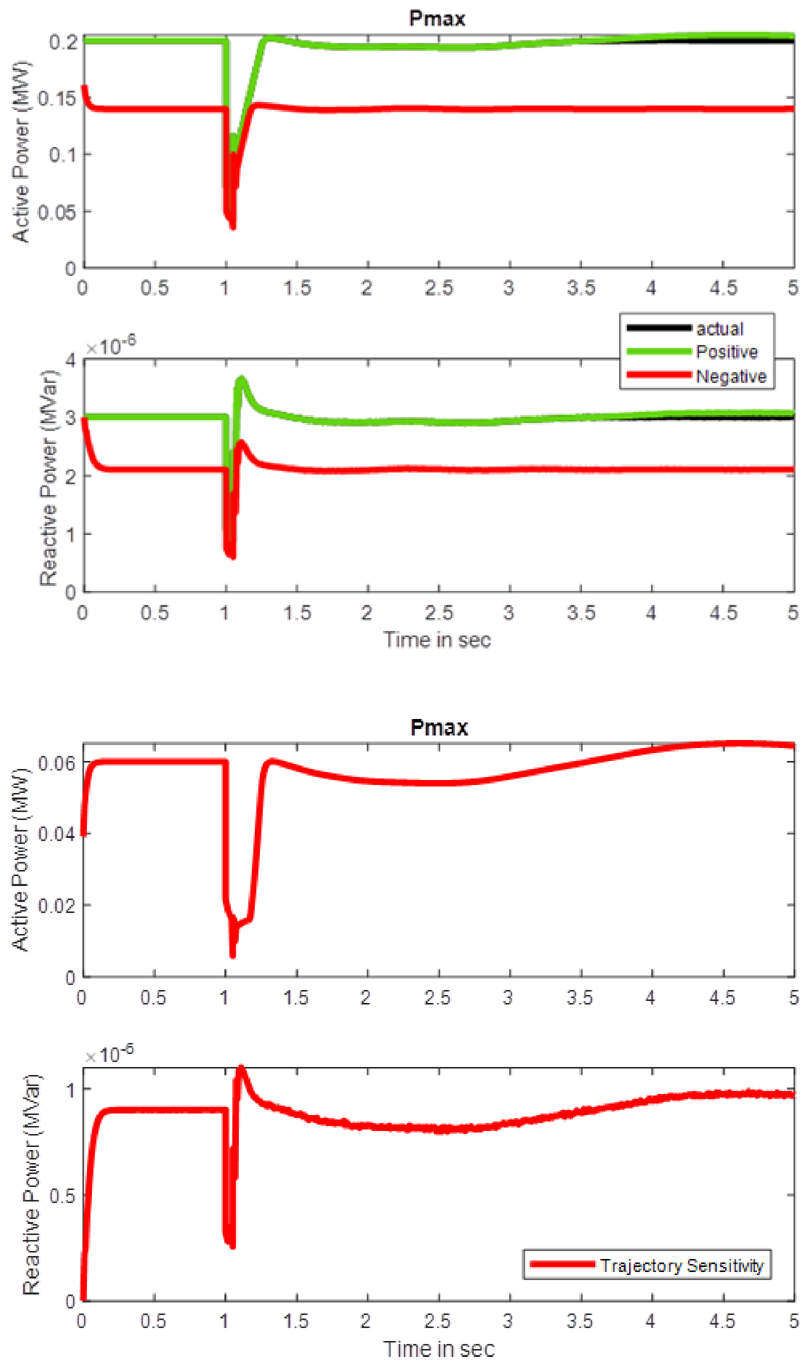


**Figure D.2: Simulation Output and the Resulting TSA Calculation on Pmax.**

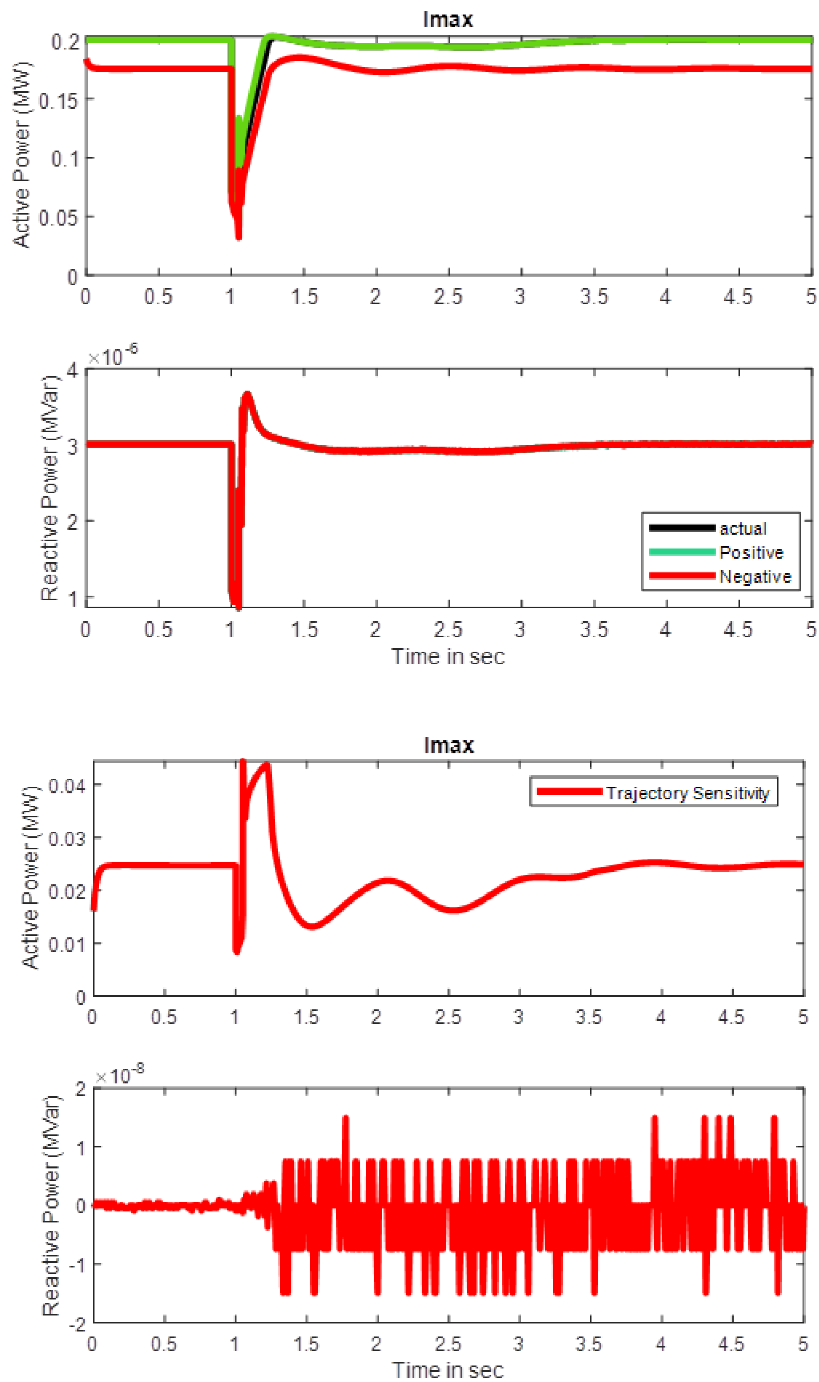


**Figure D.3: Simulation Output and the Resulting TSA Calculation on Imax**

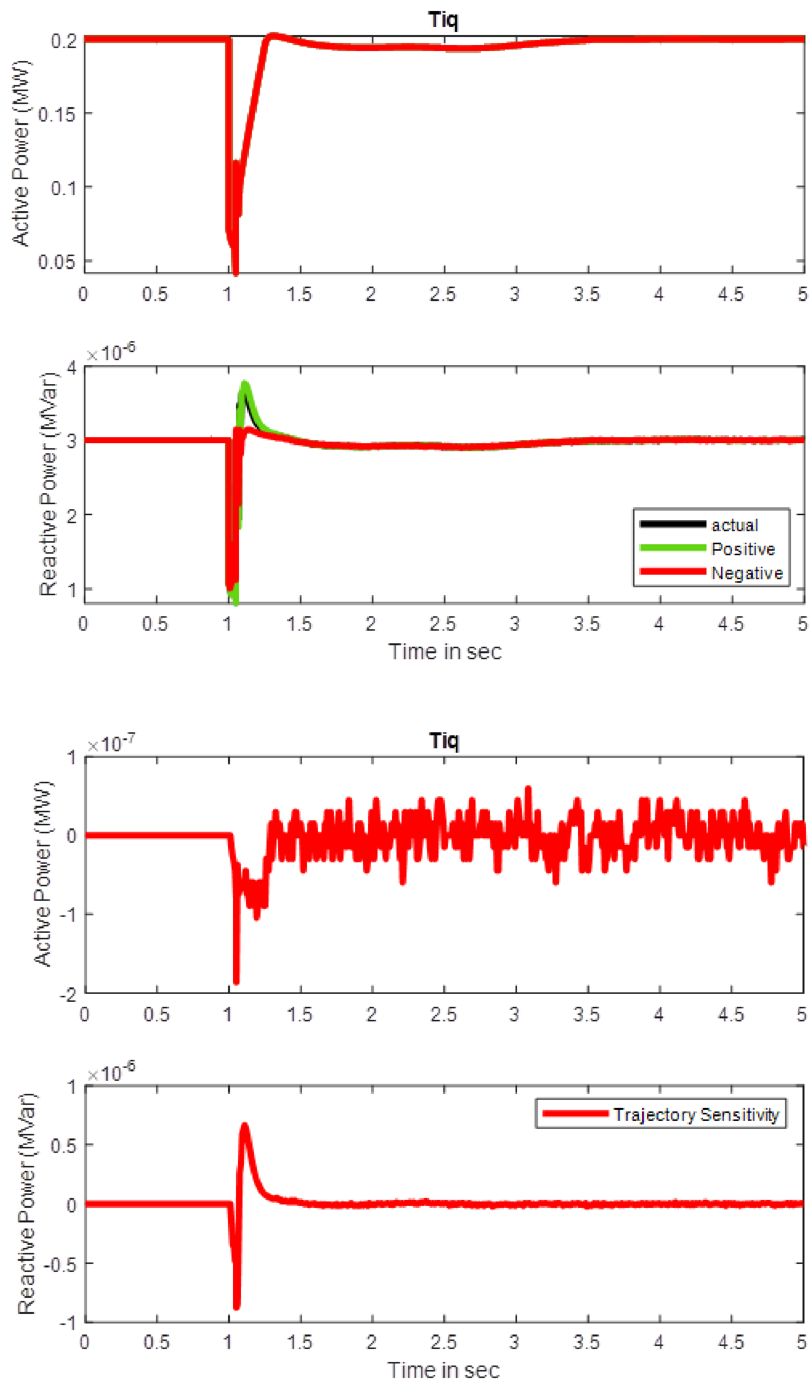


**Figure D.4: Simulation Output and the Resulting TSA Calculation on Tiq.**

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 (i.e., PfFlag, FreqFlag, PQFlag, GenFlag, VtripFlag, and FtripFlag). **Figure D.5** shows where these flags are located with respect to the DER_A dynamic model.

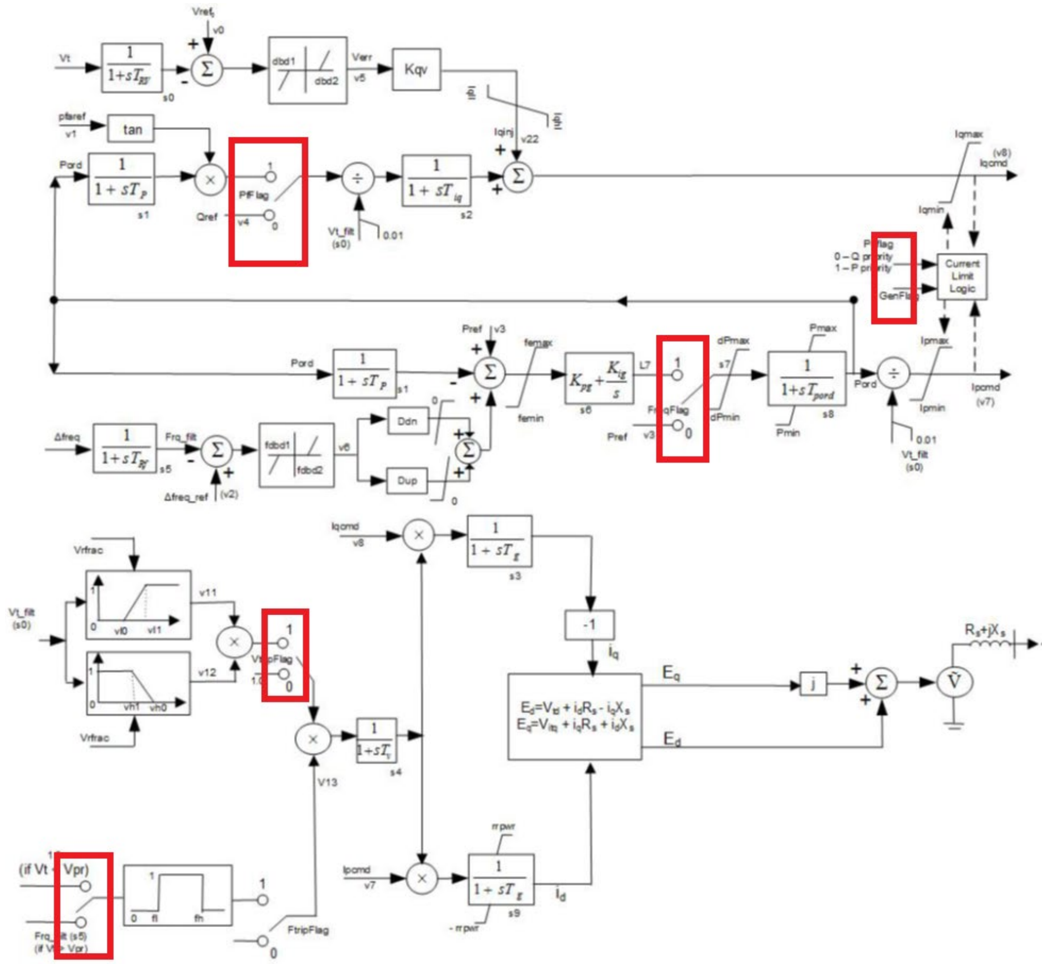


**Figure D.5: DER_A Control Block Diagram in PSS®E [Source: Siemens PTI][179]**

[179] PSSE model documentation

# Appendix E: Hypothetical Dynamic Model Verification Case

To assist in developing more complex verification cases and to demonstrate certain aspects of the reliability guideline stated in **Chapter 3**, 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.

## Model Setup

In **Figure E.1**, a synchronous machine infinite bus 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, so the transmission system is modeled as a jumper.

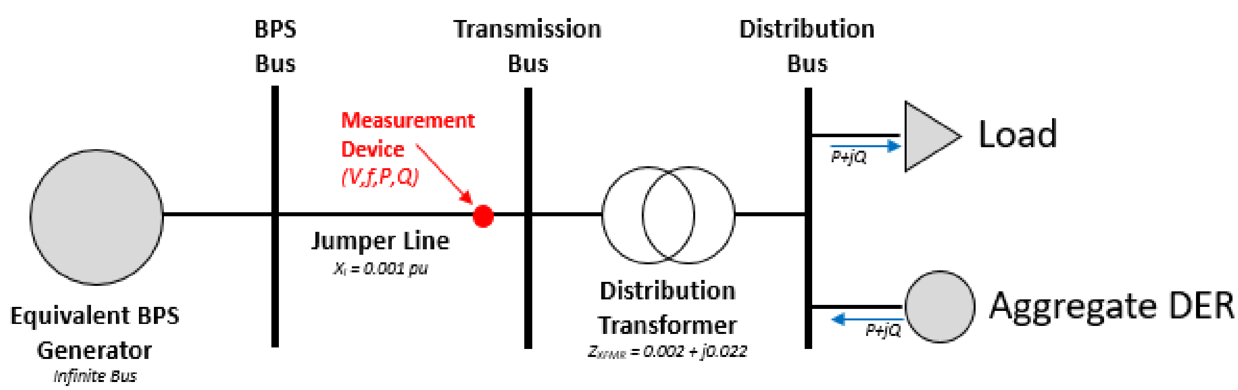


**Figure E.1: Simulation Synchronous Machine Infinite Bus Representation for High Level Aggregate U-DERs**

To populate the parameters in the representation, **Table E.1** provides the numerical parameters assumed in the setup of the powerflow. The transformer MVA rating is 80 MVA, and the study assumes that the transformer values have been tested upon manufacturing and verified at the T–D bank installation.

| Table E.1: Steady-State Parameters for Study | |
|---|---|
| **Input Name** | **Value** |
| Load | 60+j30 MVA |
| Aggregate DER | 10+j1 MVA |

In order to populate the composite load model, the parameters in **Figure E.2** were chosen and are assumed to represent the induction motors and other load characteristics. This example is set to verify the dynamic parameters of the aggregate DER and assumes the impacts are separate from the load response and are fully attributed to the DER. The list of parameters that were provided in the original model is in **Figure E.2;** it 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 E.1**. In this example, the following models[180] were used to playback 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 E.1**. The following models were chosen for this simulation:

- 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 playback the frequency and voltage signals
- Imetr: Used to monitor the flows at the high end of the T–D transformer where the measurement is located (this model records MW, MVAR, 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

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

```
#
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 E.2: Starting Set of Dynamic Parameters**

# Model Comparison to Event Measurements

The event that was chosen to verify this set of models was a fault that occurred 50 miles away from the measurement location; the fault caused a synchronous generator to trip off-line. The measurements shown here are simulation outputs from a different set of parameters and are assumed to be the reference MW and MVAR measurements for verification purposes. For illustration purposes, the event is assumed to be a balanced fault.[181] The event is detailed in the first set of graphs in **Figure E.3**. The active power and reactive power measurements are taken at the high side of the T–D transformer corresponding to **Figure E.1**. To ensure that the load model was performing as anticipated during the event, the active powers from the load were recorded in **Figure E.4**. There were two separate distinctions in the process:

- The load model responded similarly between the measurement values and the reported model.
- The changes and adjustments to the DER model did not impact the response in a way that would misalign the model with the measurements.

[181] 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.

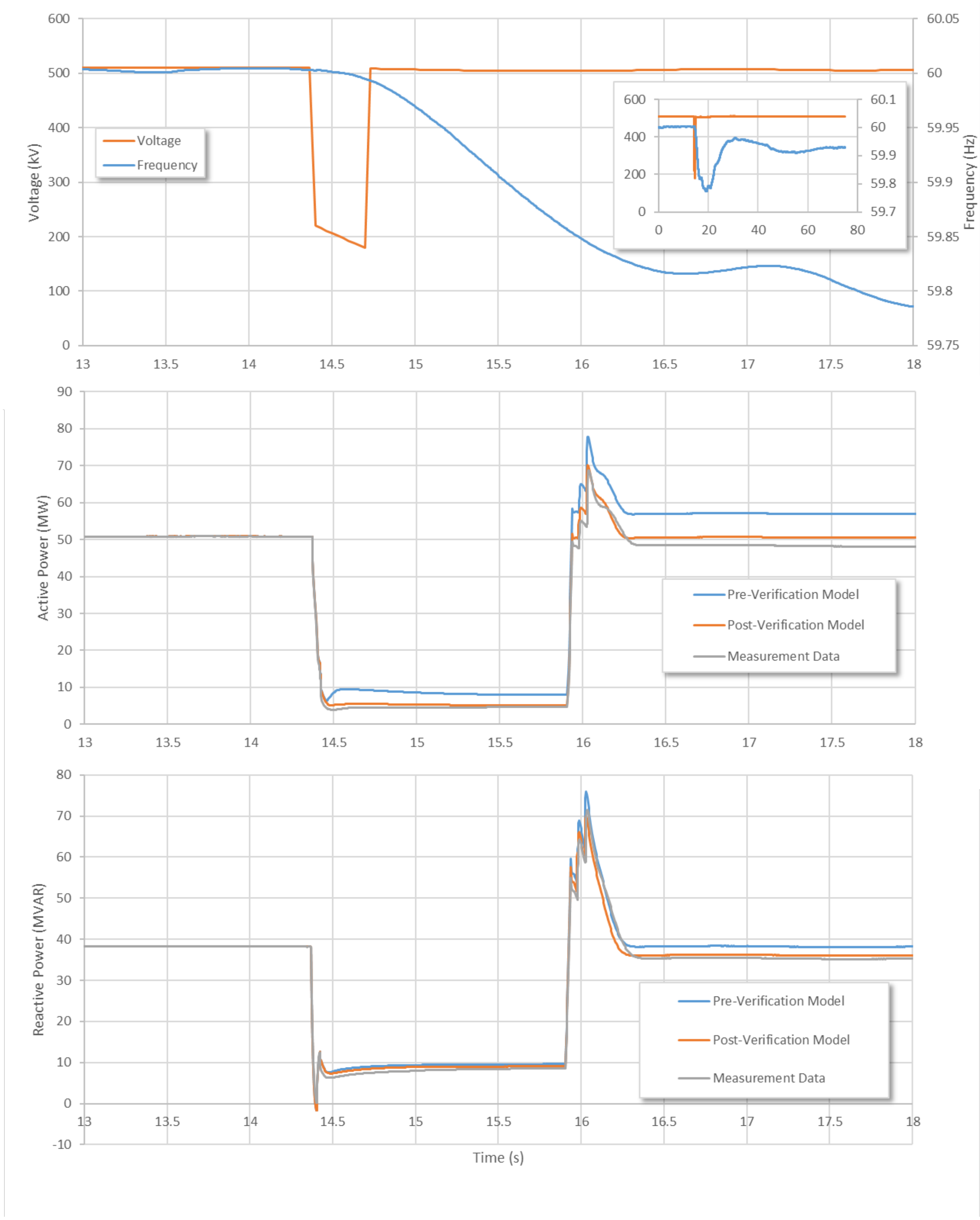


**Figure E.3: Voltage, Frequency, Active, and Reactive Power Measurements**

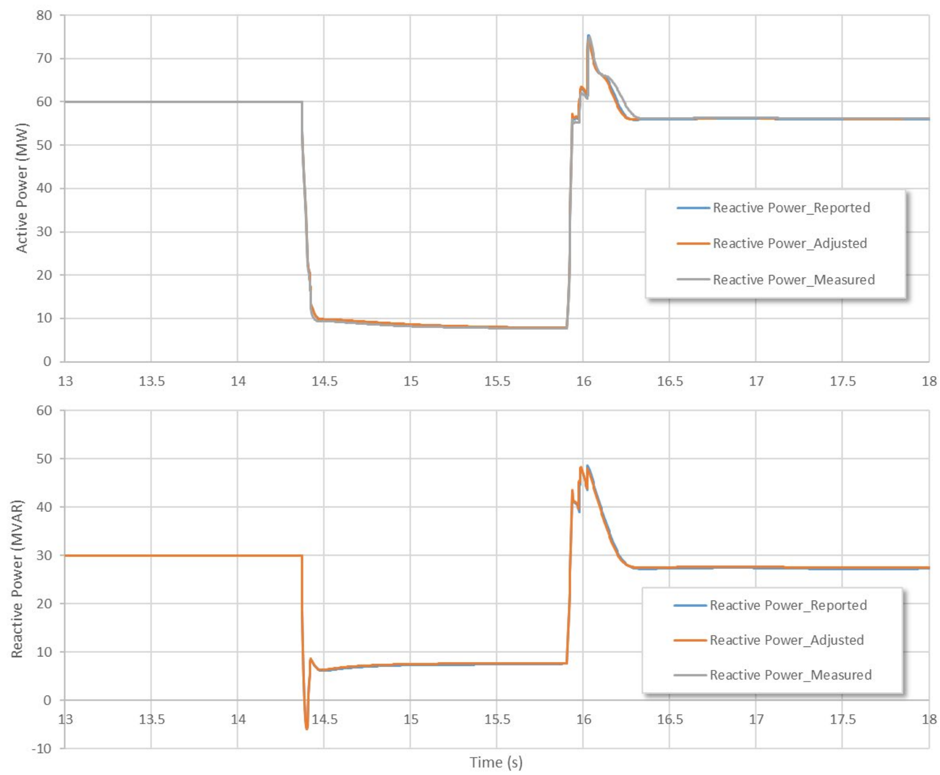


**Figure E.4: Active and Reactive Power of Load Model**

The model and measured power were very similar during the disturbance across the T–D transformer but differed during the post-disturbance recovery. After demonstrating that the two active power measurements across the transformer were not equivalent, the study engineer identified candidate parameters for model verification. The low voltage ride-through settings seemed to be too restrictive in the model, so the parameters were adjusted as detailed in **Table E.2**.

**Table E.2: DER Parameter Changes**

| Parameter Name | Pre-Verification Value | Post-Verification Value |
|---|---|---|
| Vrfrac | 0.00 | 0.20 |
| Vfth | 0.80 | 0.40 |
| Vl0 | 0.44 | 0.35 |
| Tvl0 | 0.16 | 0.75 |
| Tvh0 | 0.16 | 0.75 |

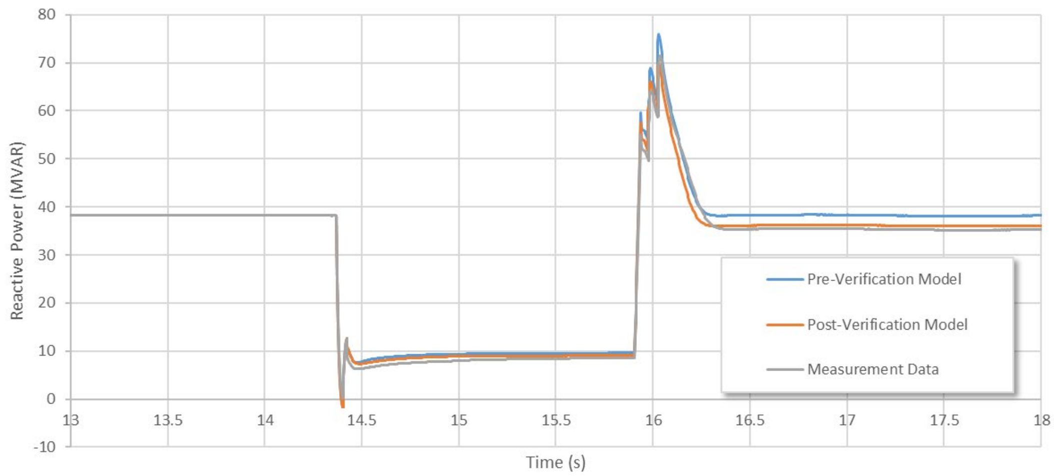


**Figure E.5: Active Power of Model versus Measurements after Parameter Adjustment**

After the adjustments were made in **Table E.2**, the simulation was performed once more and the active power looked at again to determine the effect of the changes. This comparison is reproduced in **Figure E.5**. Based on the proximity of the orange and grey lines in **Figure E.5**, the verification process ends and the model is now verified against this particular event's performance. If the TP/PC determines that this verification is not adequate, the process would repeat with more fine adjustments made until there is 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.

# Appendix F: DER Measurement Collection Example

Specific types of BPS events have demonstrated a characteristic response in load meters that has been attributed to DER response.[182] A majority of TPs or PCs, however, may not have seen these types of system-level measurements and practices when applying the process to a set of aggregate DER models. This appendix provides TPs and PCs with an example of DER response to BPS events. It also suggests methods or ideas to consider when using 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 occurring events. An example of the performance expected can be found in **Figure F.1**, which shows an example of U-DERs responding to a 500 kV single-line-to-ground fault at Independent Electricity System Operator (IESO, Ontario). More than 30 DER meters recorded interruptions upon the fault and **Figure F.1** highlights seven locations as far as 300 km from the fault (voltage and current waveforms side by side, with nameplate MW indicated). The DERs were all installed under IEEE 1547-2003, so most of them tripped off-line 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 the point of connection.

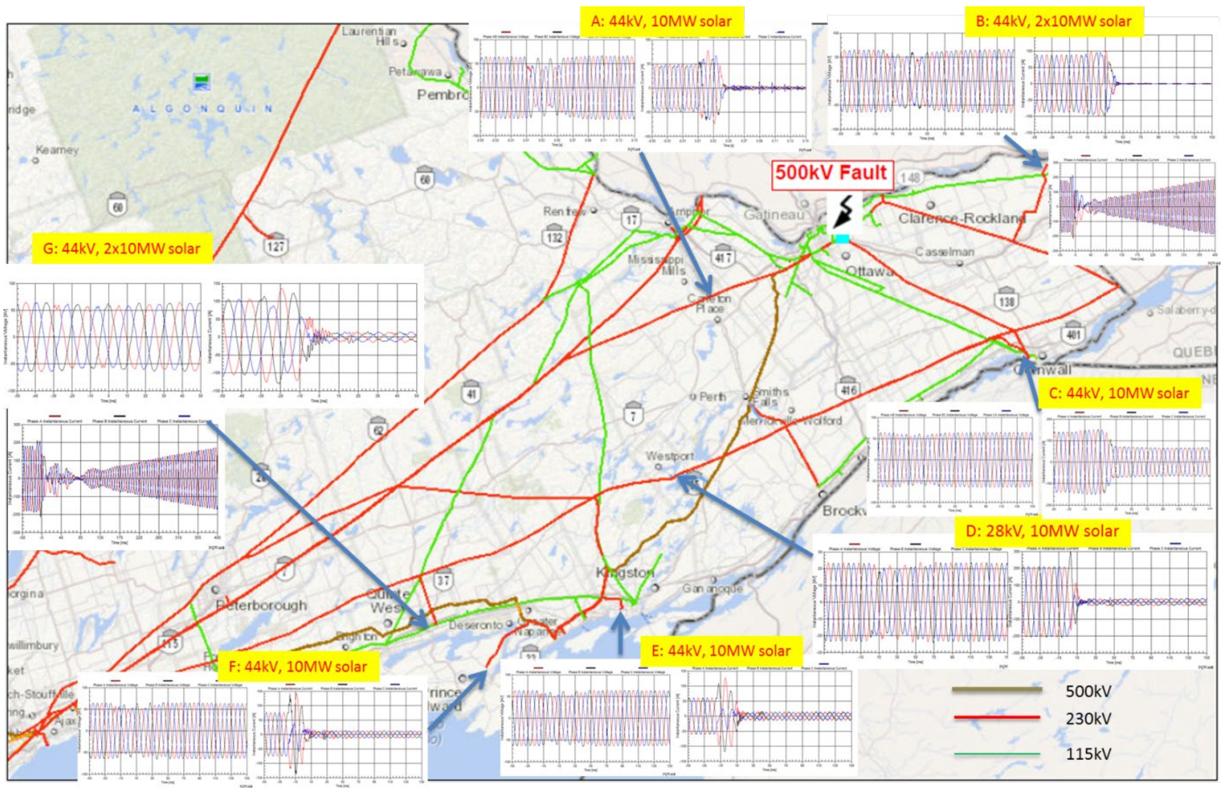


**Figure F.1: Solar U-DER Voltage and Current Waveforms for a 500kV Fault**

TPs can further verify the tripped loss of DERs by using aggregated measurements from revenue meters at the substation. **Figure F.2** plots current waveforms from one out of two paralleled 230/44 kV step-down transformers at

[182] https://www.nerc.com/pa/rrm/ea/April_May_2018_Fault_Induced_Solar_PV_Resource_Int/April_May_2018_Solar_PV_Disturbance_Report.pdf

Site B, where multiple solar generators are connected through the substation to 44 kV feeders. The fault started near 0.0s in **Figure F.2** and was cleared after three cycles (0.05 seconds). Increased net load current through the transformer can be seen after the fault cleared, suggesting most solar DERs could not recover immediately after fault clearing.

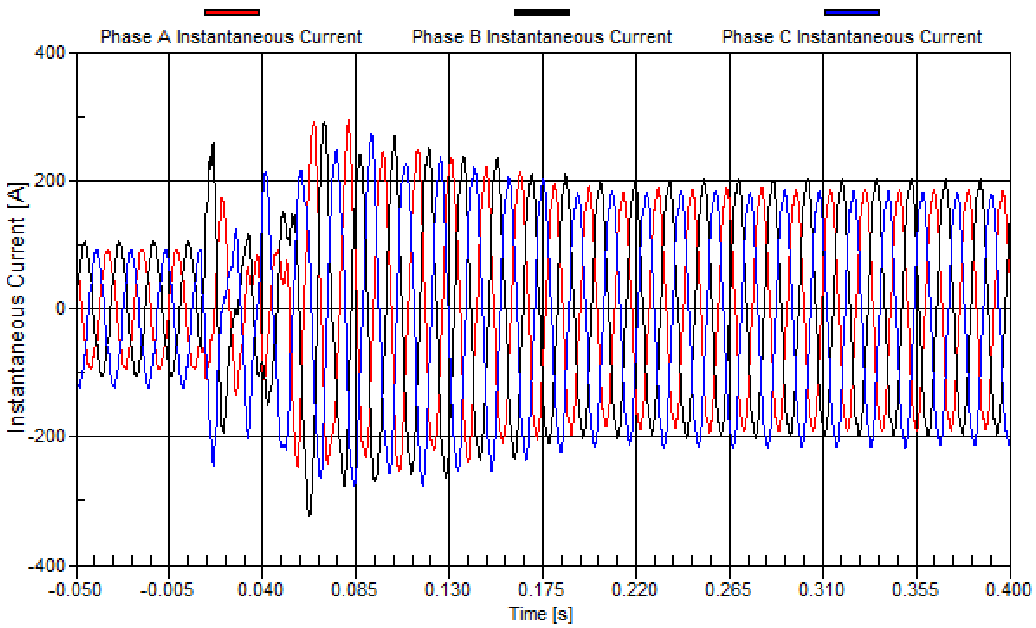


**Figure F.2: Current Waveforms from 230/44kV Transformer at Site B**

DER operating logs show various reasons that may initiate DER shutdown, such as under/over-voltage, frequency deviations or current/voltage imbalance. 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 even those short 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 decision to trip off-line was delayed.

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

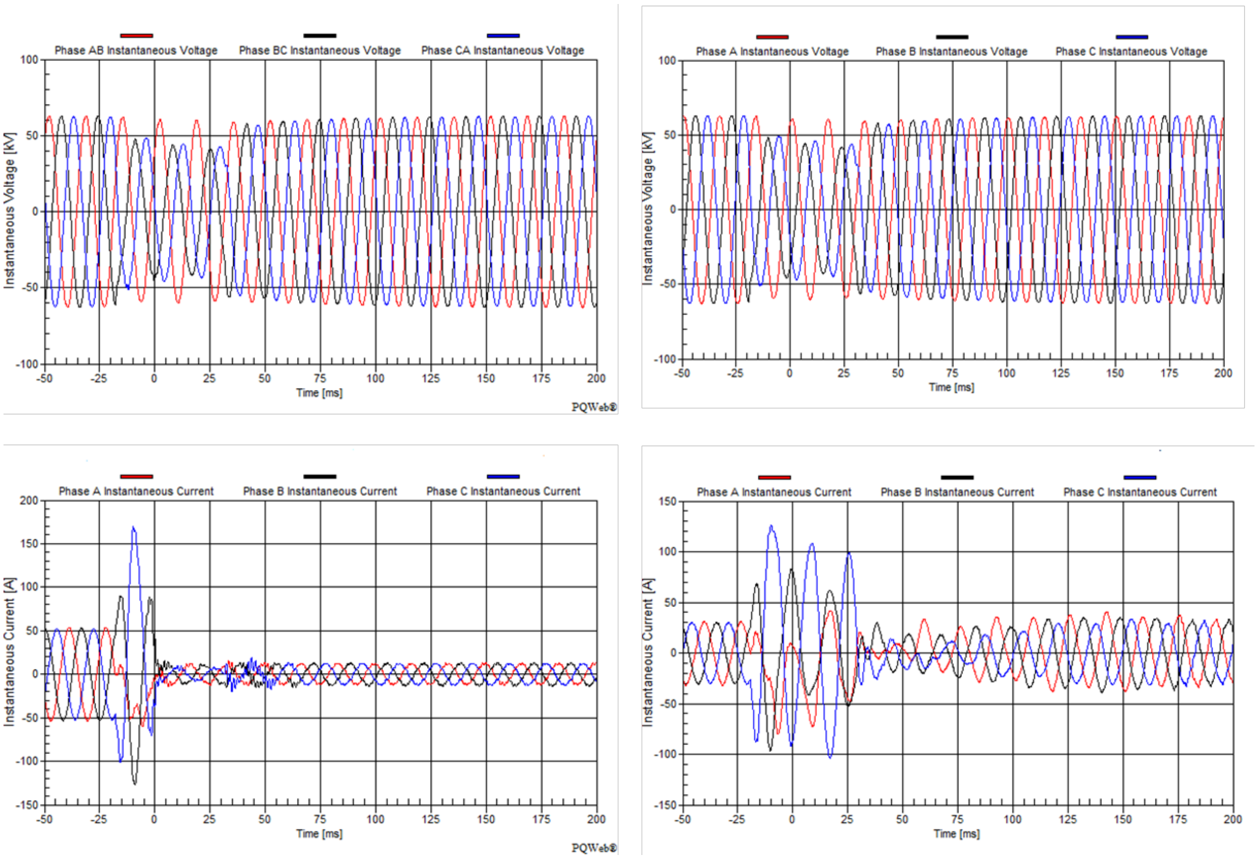


**Figure F.3: Comparison of Two Adjacent Solar Plants' Responses to the Same 500kV Fault (top: voltage, bottom: current)**

Installation data may suggest the overall majority of DERs are solar generators, but wind turbine connections are also common in some utility distribution systems. Operation records show that wind DERs may experience similar interruptions as solar under BPS disturbances. **Figure F.4** and **Figure F.5** show Type IV and Type III wind plant responses to a common 500 kV bus fault, respectively. While the wind plants are connected at different locations and voltage levels (28 kV vs. 44 kV), both shut down under the BPS fault. **Figure F.6** shows a load current increase measured from one out of two paralleled 115 kV/44 kV step-down transformers as a result of wind generation loss in the 44 kV 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 an issue is expected to diminish with the new 2018 standard revision, which requires at least a 160 ms time delay to accommodate transmission fault clearing.

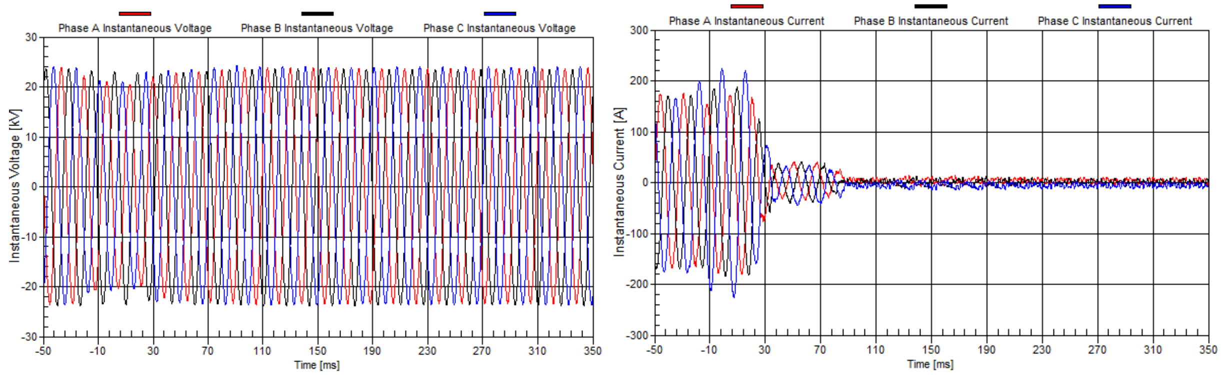


**Figure F.4: Type IV Wind Plant (28kV/10MW) Response to 500kV Single-Line-to-Ground Fault**

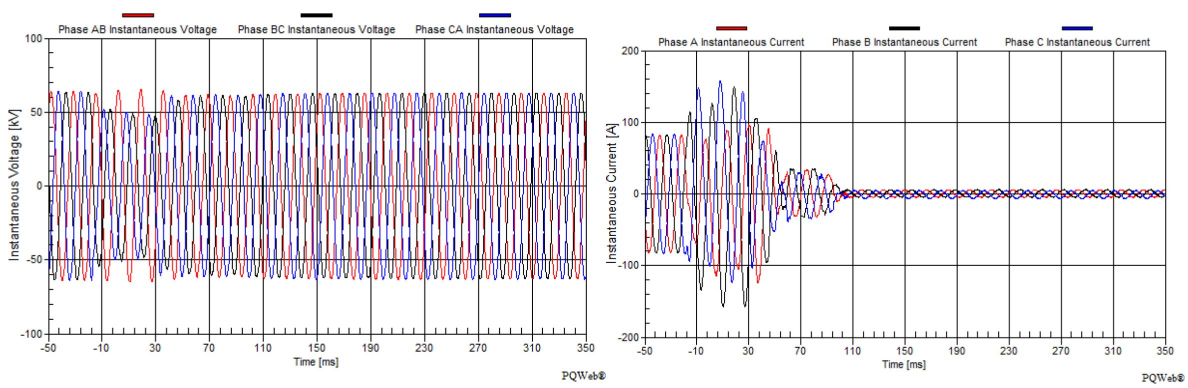


**Figure F.5: Type III Wind Plant (44 kV/10 MW) Response to 500kV Single-Line-to-Ground Fault**

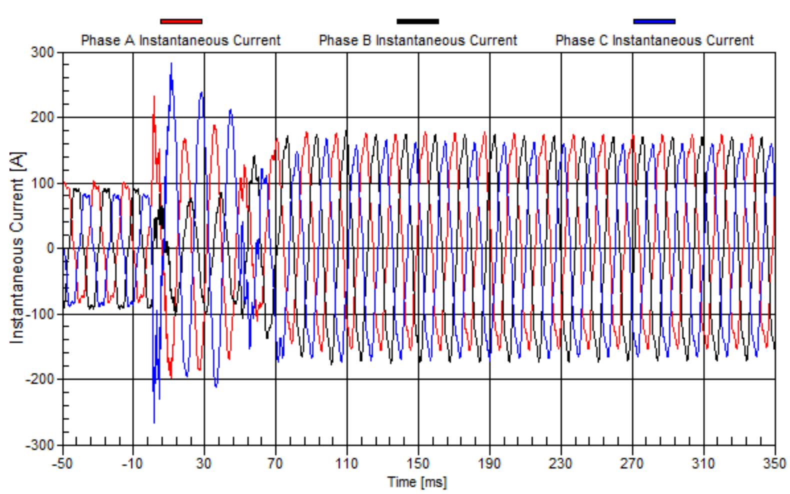


**Figure F.6: Load Current Increase at a 115 kV/44 kV Transformer after Loss of Wind Generation**

## April–May 2018 Disturbances Findings

A noticeable amount of net load increase was observed during the Angeles Forest and Palmdale Roost disturbances.[183] DERs were verified to be involved in the disturbance using a residential rooftop solar PV unit captured in the Southern California Edison 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 BTM solar PV DERs; however, the availability, resolution, and accuracy of this information was fairly limited at the time of the event analysis. **Figure F.7** shows the California Independent System Operator (CAISO) net load for both disturbances. It is challenging to identify exactly[184] the amount of DERs that either momentarily ceased current injection or tripped off-line with BA-level net load quantities. Note that these measurements were taken at a system-wide level and represent many T–D interfaces while the IESO example in **IESO DER Performance Under BPS Fault Conditions** is for specific T–D interfaces.

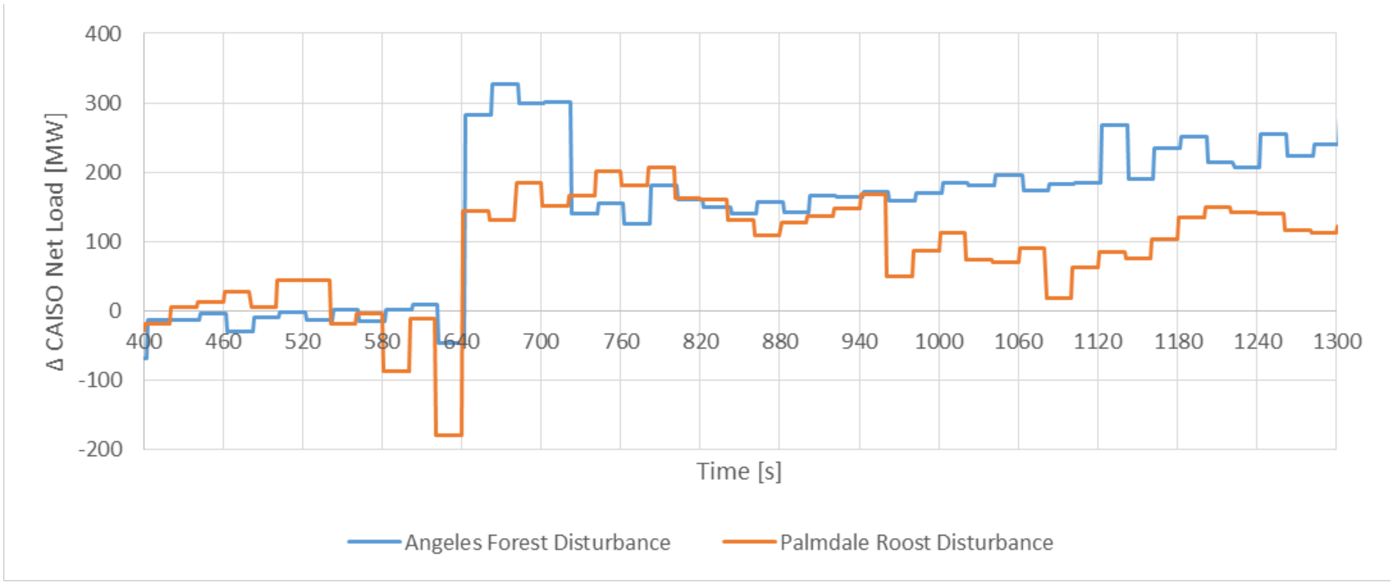


**Figure F.7: CAISO Net Load during Angeles Forest and Palmdale Roost Disturbance [Source: CAISO]**

SCE also gathered net load data for these disturbances (shown in **Figure F.8**). While an initial spike in net load was 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[185] 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.[186] Therefore, the SCADA point does not differentiate between changes in net load and changes in losses.
- Typically for energy management systems, the remote terminal units that report data to the EMS are not time-synchronized. Delays in the incoming data during the disturbance can result in temporary spikes. Fast

[183] https://www.nerc.com/pa/rrm/ea/Pages/April-May-2018-Fault-Induced-Solar-PV-Resource-Interruption-Disturbances-Report.aspx
[184] 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.
[185] Generally, generation greater than 1 MW is metered by SCE on the distribution, subtransmission, and transmission system.
[186] Net Load + Losses = Metered Generation + Intertie Imports

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 these reasons, the spikes in net load were noted as calculation errors, 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 with area-wide net load SCADA points.[187] TPs and PCs, when gathering data for use in verification of DER models, should consider the bullet points above when using SCADA or other EMSs to verify DER models, especially when using system-wide measurements.

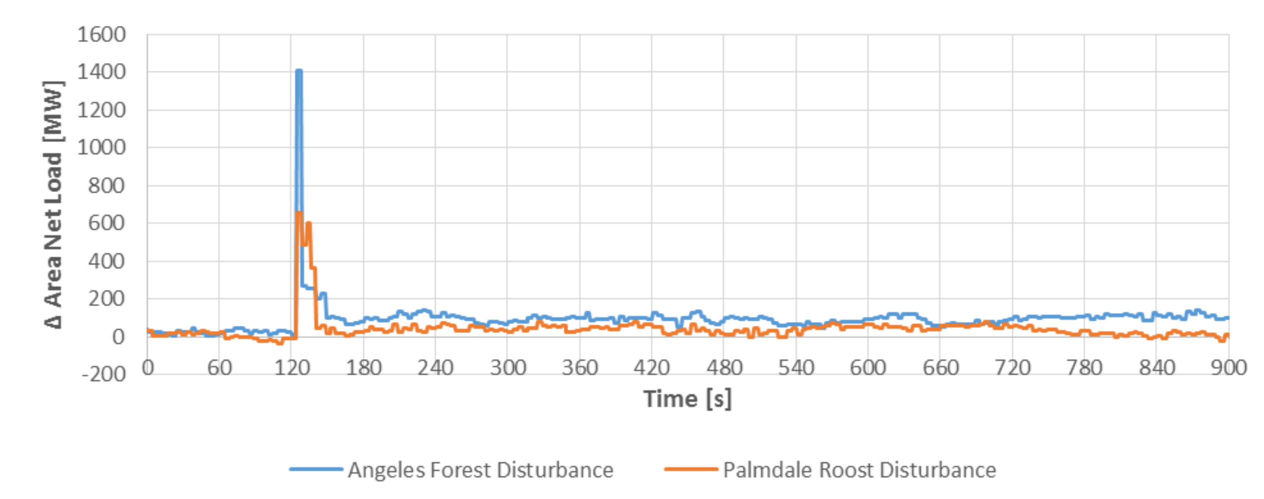


**Figure F.8: SCE Area Net Load Response (Source: SCE)**

Monitoring the T–D transformer bank flows with 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 in this section. **Figure F.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.[188] After that time, the net loading returned 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 it is 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 DER data collection and to identify or attribute responses in already collected data, especially for higher impact T–D interfaces.

[187] For that matter, SCADA scans are not recommended to determine the total tripping of any IBR resource, including DERs that are IBRs.
[188] 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

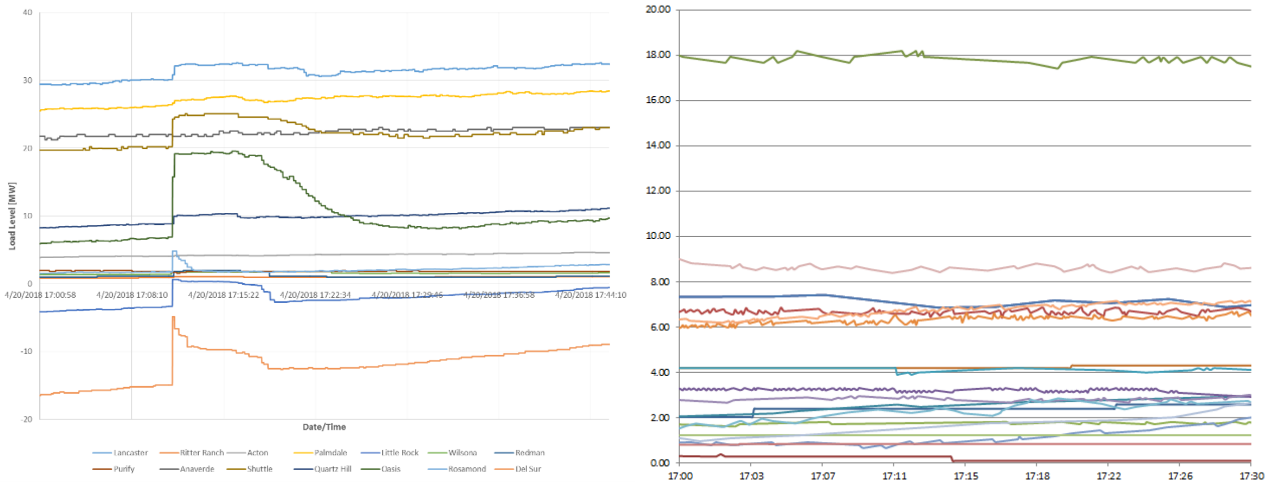


**Figure F.9: SCE (left) and PG&E (right) Individual Load SCADA Points**

# Guideline Information and Revision History

| Guideline Information | |
|---|---|
| **Category/Topic:**<br>DER | **Reliability Guideline/Security Guideline/Hybrid:**<br>Reliability Guideline |
| **Identification Number:**<br>RG-DER-1222 | **Subgroup:**<br>SPIDERWG |

| Revision History | | |
|---|---|---|
| **Version** | **Comments** | **Approval Date** |
| 1 | | |
| | | |
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# Contributors

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# Metrics

Pursuant to the Commission's Order on January 19, 2021, *North American Electric Reliability Corporation*, 174 FERC ¶ 61,030 (2021), reliability guidelines shall now include metrics to support evaluation during triennial review consistent with the RSTC Charter.

**Baseline Metrics**

All NERC reliability guidelines include the following baseline metrics:

- BPS performance prior to and after a reliability guideline as reflected in NERC's State of Reliability Report and Long-Term Reliability Assessments (e.g., Long-Term Reliability Assessment and seasonal assessments)
- Use and effectiveness of a reliability guideline as reported by industry via survey
- Industry assessment of the extent to which a reliability guideline is addressing risk as reported via survey

**Specific Metrics**

The RSTC or any of its subcommittees can modify and propose metrics specific to the guideline in order to measure and evaluate its effectiveness, listed as follows:

- Established TP and PC criteria for metering and monitoring of DER behind a transmission to distribution interface
  - Percentage[189] of DER MW that has been validated through electronic relays or digital fault recorders
  - Percentage of DER MW that has been validated through non-measurement methods
- Percentage of MW of DER modeled[190] in a transmission base case compared to the total capacity[191] of DER reported in the NERC Long-Term Reliability Assessments for a given year, adjusted for resource categorization shifts
- Count of TPs and PCs that have identified specific modeling requirements for DER in transmission-level studies
  - Count of entities that have used identified specific modeling requirements to develop DER models
  - Percentage of TPs and PCs of the above representing DER by total of NERC Compliance Registry
- For grid disturbances that have identified a DER response, percentage of the DER model representing that equipment matches the grid disturbance [192]

NERC is asking entities who are users of Reliability and Security Guidelines to respond to the short survey provided in the link below.

[Effectiveness Survey: DER Data Collection and Model Verification of Aggregate DER]

[189] Percentage is calculated by the ratio of verified DER models toward all DER models in a planning case.
[190] This includes both explicitly modeled DER as generators or DER modeled using the dg fields in the load model.
[191] Calculated using best available capacity factors and engineering judgement to align the generation in the base case to nameplate capacity.
[192] This metric will require careful engineering judgement by NERC's Event Analysis department as well as the NERC RSTC.

# Errata

**Date:**