NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Guideline

DER Data Collection for Modeling in Transmission Planning Studies

September 2020

RELIABILITY | RESILIENCE | SECURITY




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Table of Contents

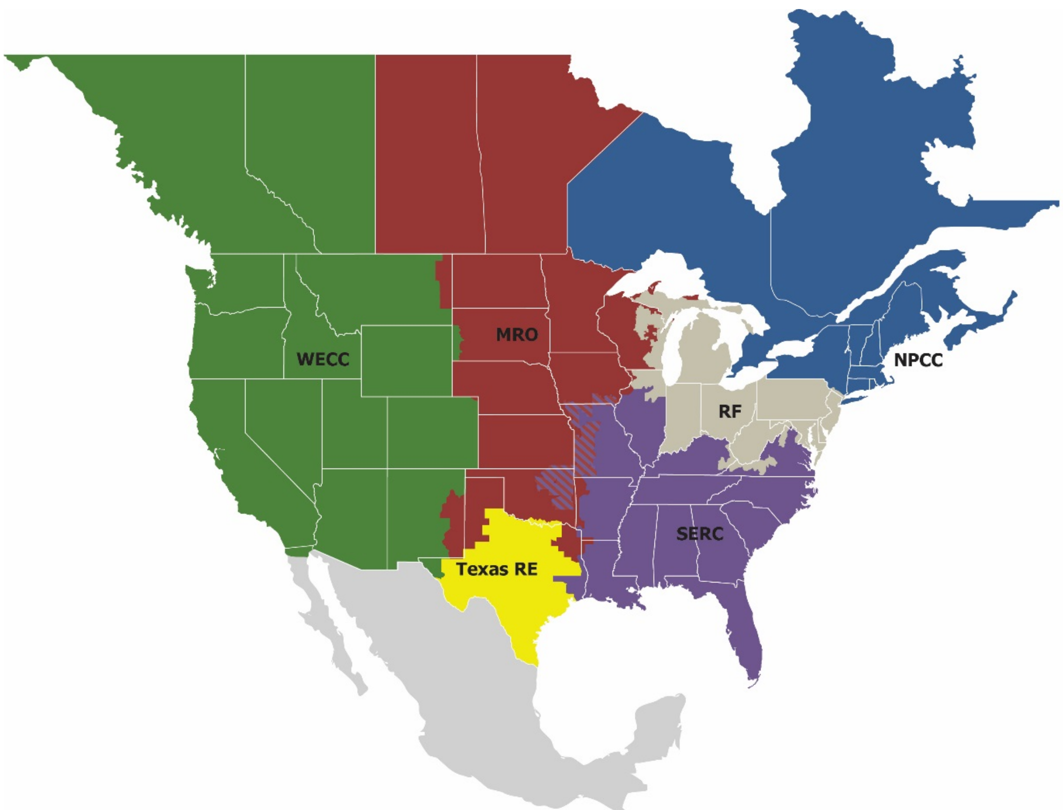
Preface

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

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

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



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 bulk power system (BPS) operations, planning, and security. Reliability guidelines provide key practices, guidance, and information on specific issues critical to promote and maintain a highly reliable and secure BPS.

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

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 (DERs).[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 (TPs) and Planning Coordinators (PCs) to develop models of aggregate amounts of DERs for planning purposes.

TPs and PCs establish modeling data requirements and reporting procedures per the requirements of NERC Reliability Standard MOD-032-1.[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 (DPs), Resource Planners (RPs), 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-DERs) and retail-scale DERs (R-DERs) 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. MOD-032 designees that develop Interconnection-wide planning cases should also ensure clear and consistent requirements for TPs and PCs to accurately account for aggregate amounts of DERs in the planning cases. TPs and PCs should also establish clear requirements and any applicable thresholds regarding DER modeling practices; however, aggregated amounts of DERs should be accounted and reported to the TP and PC for modeling purposes.[6] Any 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 studies.

The goal of this reliability guideline is to provide clear recommendations and guidance for establishing effective modeling data requirements on collecting aggregate DER data for the purposes of performing 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 the purposes of modeling may not require detailed information from individual DERs; rather, aggregate data related to location, type of DERs, vintage of IEEE 1547, interconnection time line and projections, and other key data points can help develop aggregate DER models. In instances of larger U-DERs, more detailed modeling information may be needed if those DERs can have an impact on BPS performance. In either case, the TP and PC should coordinate with the DP and any other external entities on the best approaches for gathering aggregate DER data for modeling purposes.

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[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 are 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/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.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.

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[7] as well as a growing focus on the representation of aggregate amounts of DERs. TPs and PCs are establishing modeling data requirements for DER data for the purposes of transmission planning assessments, and reasonable representation of 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 primary objective of this reliability guideline is to provide recommended practices for TPs and PCs to establish effective modeling data 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. The detailed guidance provided in this guideline follows the required data transfer established in NERC Reliability Standard MOD-032-1. Data collection requirements and reporting procedures established by each TP and PC are expected to vary slightly based on the types of studies being performed as well as how those studies are performed. However, there are commonalities in the type of data needed to model DERs and in how that data can be collected.

Background

The NERC *Reliability Guideline: Modeling DER in Dynamic Load Models*,[8] 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*,[9] 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*[10] 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.

The NERC Distributed Energy Resources Task Force (DERTF) also published a technical report on *Distributed Energy Resources: Connection Modeling and Reliability Considerations,*[11] published December 2016, and a technical brief on *Data Collection Recommendations for Distributed Energy Resources,* published March 2018.[12] Both of these reports provided industry with a high-level overview of the information that may need to be collected and shared among

[7] 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.

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

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

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

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

[12] https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/DER_Data_Collection_Tech_Brief_03292018_Final.pdf

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 System Planning Impacts from Distributed Energy Resources Working Group (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.

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**).[13] For the 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.[14] 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,[15] commercial, and industrial customers. Typically, the residential units are single-phase while the commercial and industrial units can be single- or three-phase facilities.

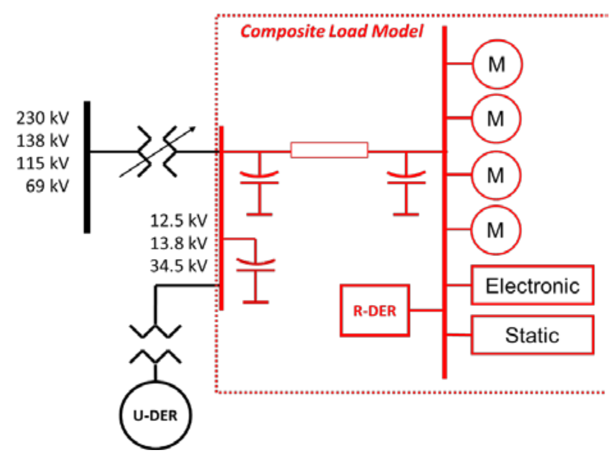

Figure I.1: DER Modeling Framework

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 system 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[16] to be a contributor to BPS performance during disturbances.

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

[14] 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.

[15] 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.

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

Types of Reliability Studies

Data of BPS elements as well as other necessary aspects[17] of the interconnected BPS are used in a wide array of reliability studies performed by TPs and PCs. In particular, studies considered by SPIDERWG include the following:

- **Steady-State Studies:[18]** Steady-state reliability studies include both power flow analysis and steady-state contingency analysis of future operating conditions.[19] In addition, steady-state stability studies typically include voltage stability[20] 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:[21]** 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 all the elements connected to it. The data used in these simulations also represents the aggregate[22] 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.[23] 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.[24] In many cases, the details of individual DERs are not relevant unless their individual size is deemed impactful[25] to BPS performance. A reasonable understanding of the aggregate behavior of DERs is more suitable for most dynamic simulations.[26] 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.

[17] Such as aggregate demand (steady-state) and the dynamic nature of end-use loads (dynamics)
[18] Fundamental-frequency, positive sequence, phasor simulations
[19] 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.
[20] Active power-voltage (P-V) and reactive power-voltage (Q-V) analysis
[21] Fundamental-frequency, positive sequence, phasor simulations
[22] Or possible individual large loads or resources connected to the distribution system if they can potential have an impact to the BPS
[23] 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).
[24] https://www.ofgem.gov.uk/publications-and-updates/ofgem-has-published-national-grid-electricity-system-operator-s-technical-report
[25] 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.
[26] 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,[27] which analyzes the risk to BPS reliability that could be caused by quasi-dc geomagnetically induced currents (GICs) 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.[28]
- **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 benchmarking positive sequence fundamental-frequency phasor models. Items such as ride-through and voltage response can be better represented in EMT studies than 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[29] 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 becoming 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 that is closely linked to the assumptions used in creating 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.

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[27] https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=TPL-007-3&title=Transmission%20System%20Planned%20Performance%20for%20Geomagnetic%20Disturbance%20Events&jurisdiction=United%20States

[28] 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.

[29] The term "large" is relative to each specific system and will need to be considered by each TP and PC. However, in order 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.[30]
- **Season:** Each base case typically has a specified season (e.g., summer, spring, winter) or type of season (e.g., shoulder season), which is already defined in the planning process.
- **Time of Day:** Each TP and PC should identify the critical times of day that should be studied; 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 needed. These dispatch assumptions may include both active power output levels and reactive power capability. Additional planning base cases should reflect expected stressed system conditions that depend on the geospatial and temporal patterns (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.

[30] 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 their 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.[31] 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 as well.

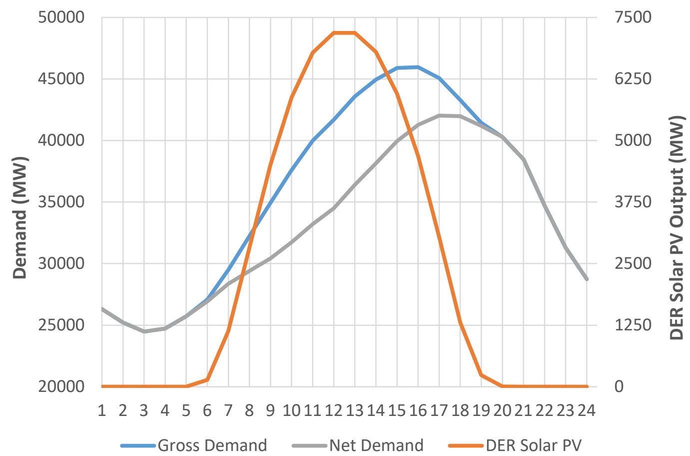

Figure I.2: DER and Demand Profiles for Summer Peak Condition [Source: CAISO]

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 necessary DER data needed to represent the aggregate DER in planning cases.

Time Line and Projections of DER Interconnections

The TP and PC are focused on developing planning base cases with reasonable assumptions of future BPS scenarios, including BPS generation, demand, and aggregate DERs. Accounting for the currently installed penetration of DERs helps the TP and PC understand what the existing system contains regarding DERs. This information, in most cases, should be provided by the DP to support data sharing across the transmission-distribution interface. 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.

Visualization of DER penetration, both existing and forecasted values, can be useful to the TP for the purposes of 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.[32]

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

[32] The Electric Power Research Institute (EPRI) is launching a public, web-based DER Performance Capability and Functional Settings Database: https://dersettings.epri.com.

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.

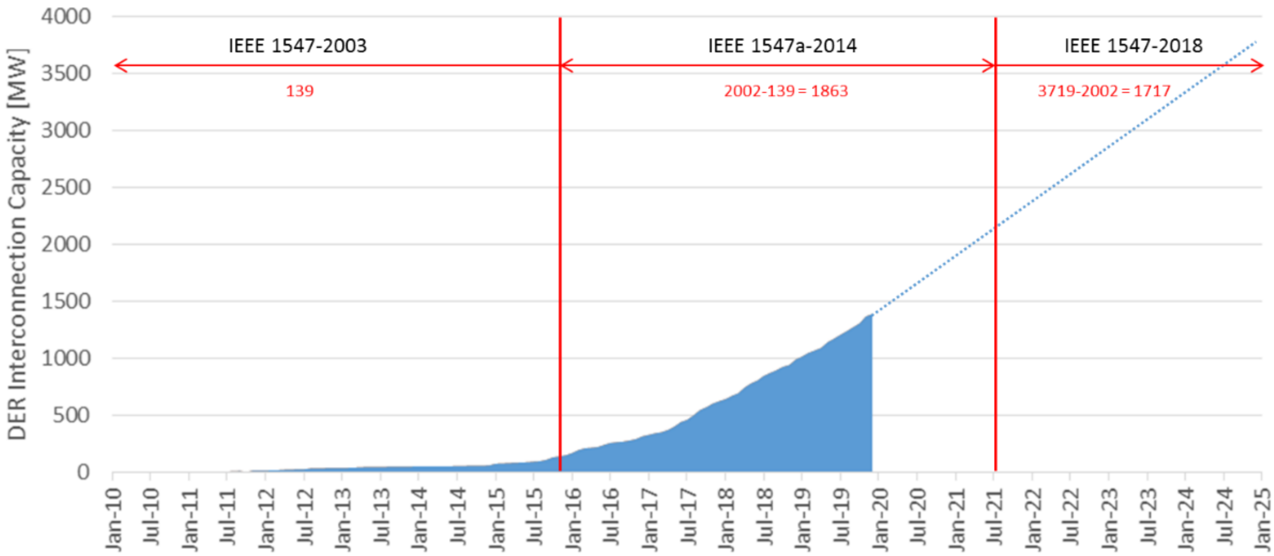

Figure I.3: Example DER Interconnection Capacity Growth

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[33] that DERs were installed with settings compliant with IEEE 1547a-2014.[34] Finally, after July 2021, assume that DERs will be installed with settings compliant with IEEE 1547-2018[35] once interconnection requirements are updated and compliant equipment becomes available. The red numbers show the amount of aggregate DER capacity that meet each standard implementation. It is clear that a small amount of resources are compliant with IEEE 1547-2003 while the remaining majority are mixed between IEEE 1547a-2014 and IEEE 1547-2018. The revised IEEE 1547-2018 includes much more robust ride-through performance and the capability for active power-frequency control on overfrequency conditions. In this example, no resources are required to maintain headroom to respond to underfrequency conditions. Interconnection requirements will presumably be updated in July 2021 to 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.

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

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[33] 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.

[34] https://standards.ieee.org/standard/1547a-2014.html

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

- 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. This is particularly important for modeling aggregate amounts of R-DERs where minimal information is available.

Chapter 1: MOD-032-1 Data Collection Process

The purpose of NERC Reliability Standard MOD-032-1 is to "establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system." MOD-032-1 serves as the foundation for the development of the Interconnection-wide planning base cases that are used as a starting point by TPs and PCs to perform their reliability assessment per the NERC Reliability Standard TPL-001. The requirements and overall flow of data is shown in **Figure 1.1**, specifically related to DER modeling information. The process is described briefly with the following 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 as well as any additional data deemed necessary for the purposes of modeling.
    - The data requirements should address data format,[36] 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[37] to provide the modeling data to the TPs and PCs according to the requirements specified.
- Requirement R3 requires each of the applicable entities to provide either updated data or an explanation with a technical basis for maintaining the current data if a written notification is provided to them by the PC or TP with technical concerns regarding the data submitted.
- Requirement R4 requires each PC to make the models for its footprint available to the ERO or its designee[38] to support the creation of Interconnection-wide base cases.

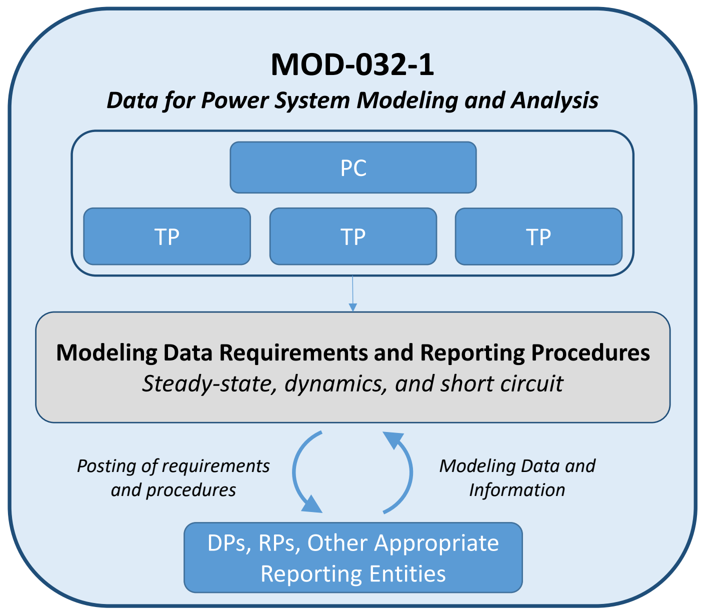

Figure 1.1: MOD-032-1 Flowchart for DER Data

MOD-032-1 Data Collection and DER

Attachment 1 of MOD-032-1 "indicates information that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning

[36] 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.

[37] Including each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, TO, and Transmission Service Provider. 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 modelling purposes. Therefore, DP is used as the applicable entity throughout this document.

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

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 *(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** *(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] a. nominal voltage b. area, zone and owner 2. Aggregate Demand[2] [LSE] a. real and reactive power* b. in-service status* 3. Generating Units[3] [GO, RP (for future planned resources only)] a. real power capabilities - gross maximum and minimum values b. reactive power capabilities - maximum and minimum values at	1. Generator [GO, RP (for future planned resources only)] 2. Excitation System [GO, RP(for future planned resources only)] 3. Governor [GO, RP(for future planned resources only)] 4. Power System Stabilizer [GO, RP(for future planned resources only)] 5. Demand [LSE]	1. Provide for all applicable elements in column "steady-state" [GO, RP, TO] a. Positive Sequence Data b. Negative Sequence Data c. Zero Sequence Data 2. Mutual Line Impedance Data [TO] 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 does not provide a line item for aggregate DER data. Rather, the table includes a statement[39] 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.[40]

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 requirements should result in the most effective outcome for gathering DER information for modeling.[41] **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.

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

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

[41] 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/.

Chapter 2: Steady-State Data Collection Requirements

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.

DER Modeling Needs for TPs and PCs

Modeling data requirements for steady-state aggregate DER data should be explicitly defined in the modeling data requirements established by each PC and TP per MOD-032-1. This section describes the recommended data necessary for representing the aggregate 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 for explicit representation in the power flow model and can then assign the gross load and aggregate DERs connected to the low-side bus accordingly. The TP and PC should establish DER data collection requirements for aggregate DER data at each T-D transformer so this can be modeled correctly.[42] 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 necessary data needed for suitable developing models.

DER models in the steady-state power flow base case, whether represented as a generator record (i.e., U-DERs) or as a component of the load record (i.e., R-DERs), have specific data points that must be accurately populated in order to represent aggregate DERs.[43] 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)[44]
- Historical or expected DER output profiles[45]
- Status
- Maximum and minimum DER active power capacity (Pmax[46] 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)
- Distribution system equivalent feeder impedance (particularly for R-DERs and load modeling)

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[42] 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.

[43] 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.

[44] 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.

[45] 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.

[46] 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.

- (U-DER) Reactive power-voltage control operating mode[47]

If one or more DERs are represented as a U-DER with a 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[48] 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[49]

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 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 are typically relatively large (e.g., 0.5 to 20 MW).[50]

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 necessary information that will be 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 considerations for distributed energy storage systems.

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 transformer (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)

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

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

[49] This is based on DER modeling practices established by the TP and PC.

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

- 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
- All DER operates at unity power factor

Table 2.1: Steady-State Power Flow Modeling Data Collection	
Aggregate DER Modeling Information Needed[51]	**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. 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.[52] 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[53] 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.

[51] 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.
[52] 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/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf.
[53] 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[51]	**Information Necessary for Suitable Modeling of Aggregate DERs**
Maximum DER reactive power capability (Qmax and Qmin)[54]	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).[55] 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.

[54] Qmax refers to producing vars, and Qmin refers to consuming vars.

[55] 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.

Chapter 3: Dynamics Data Collection Requirements

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

DER Modeling Needs for TPs and PCs

Dynamics modeling data requirements for aggregate DERs should be explicitly defined in the modeling data requirements established by each PC and TP per MOD-032-1. This section describes the recommended data necessary for representing the aggregate DER in dynamic simulations performed by TPs and PCs to ensure BPS reliability. Refer to the existing NERC reliability guidelines regarding DER modeling for more information about recommended dynamic modeling approaches for DERs. While synchronous DERs exist and some new synchronous DERs are being interconnected in varying degrees,[56] 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 the purposes of developing DER dynamic models.

The DER_A dynamic model is the recommended model for representing inverter-based DERs (i.e., wind, solar PV, and BESSs).[57] 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 (i.e., U-DERs) or closer to the end-use loads (i.e., R-DERs)?
- Are there any BPS protection schemes (e.g., direct transfer trip) that could result in the disconnection of DERs under certain BPS configurations?
- 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

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[56] 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.

[57] 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

remain fixed when representing different DER vintages or specific distribution-level interconnection requirements.[58] 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 sharing to gather the needed data for TPs and PCs to be able to model these resources. **Table 3.1** shows how parameterization of the DER_A dynamic model can be mapped to questions that should be asked by the TP and PC and to information that should be provided by the DP or other external entity to help facilitate DER model development. Note that **Table 3.1** shows default DER_A parameters to capture the general behavior of DERs compliant with IEEE 1547-2018 Category II, which is taken from NERC *Reliability Guideline: Parameterization of the DER_A Model*.[59] 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.[60] 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 intended as an example to help illustrate how the TP and PC could map questions related to DER information for the purposes of developing an aggregate DER dynamic model. 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	

[58] For example, representing DERs compliant with different versions of IEEE 1547 (e.g., -2003, -2018, etc.) or DP-specific interconnection requirements.
[59] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf
[60] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.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)?[61] 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 what vintage of IEEE 1547 the DERs are, so a time line of interconnection capacity estimating the amount and timing of DER interconnection will support modeling.
femin	-99	Values vary based on what vintage of IEEE 1547 the DERs are; so a time line of interconnection capacity estimating 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 needed from DP for the purposes of modeling, assuming that these default parameters are appropriate. In cases where the TP or PC has determined that these default parameters are not appropriate, the TP or PC may request additional information of the DP for this purpose.
pmin	0	
dpmax	99	
dpmin	-99	
tpord[62]	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 what vintage of IEEE 1547 the DERs are, so a time line of interconnection capacity estimating the amount and timing of DER interconnection will support modeling.

[61] 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 appropriate 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.

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

Table 3.1: Data Collection for Parameterizing the DER_A Dynamic Model

Param	Default	Information Necessary for Suitable Modeling of Aggregate DERs
fltrp	56.5	Values vary based on what vintage of IEEE 1547 the DERs are, so a time line of interconnection capacity estimating the amount and timing of DER interconnection will support modeling.
fhtrp	62.0	Values vary based on what vintage of IEEE 1547 the DERs are, so a time line of interconnection capacity estimating 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 needed from DP for the purposes of modeling, assuming that these default parameters are appropriate. In cases where the TP or PC has determined that these default parameters are not appropriate, the TP or PC may request additional information of the DP for this purpose.
tfh	0.16	
tg	0.02	
rrpwr	2.0	Values vary based on what vintage of IEEE 1547 the DERs are, so a time line of interconnection capacity estimating 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 needed from DP for the purposes of modeling, assuming that these default parameters are appropriate. In cases where the TP or PC has determined that these default parameters are not appropriate, the TP or PC may request additional information of the DP for this purpose.
Kpg	0.1	Values vary based on what vintage of IEEE 1547 the DERs are, so a time line of interconnection capacity estimating the amount and timing of DER interconnection will support modeling.
Kig	10.0	Values vary based on what vintage of IEEE 1547 the DERs are, so a time line of interconnection capacity estimating the amount and timing of DER interconnection will support modeling.
xe	0.25–0.8[63]	Parameter values do not generally change between vintages of IEEE 1547. No information 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 of 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 needed from DP for the purposes of modeling, assuming that these default parameters are appropriate. In cases where the TP or PC has determined that these default parameters are not appropriate, the TP or PC may request additional information of the DP for this purpose.
iql1	-1.0	
pfflag	1	
frqflag	1	
pqflag	Q priority	Values vary based on what vintage of IEEE 1547 the DERs are, so a time line of interconnection capacity estimating the amount and timing of DER interconnection will support modeling.
typeflag	1	What penetration of energy storage resources are connected to the distribution system? What percentage of DERs are energy storage? Are these larger utility-scale energy storage DERs, or more distributed (e.g., residential) energy storage DERs? Any values or estimates as the interconnection of energy storage DERs will help determine whether to and how to separate out energy storage DERs in the models.

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

[63] 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.

To recap the relevant information needed for aggregate DER dynamic modeling, the following data points should be considered by TPs, PCs, DPs, and other external entities in the development of requirements and when providing this information for modeling purposes:[64]

- 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.

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

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"[65] 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 of localized issues).
- **Setting Protective Relays:** Protective relay setting analyses study "all lines in-service" conditions as well as credible outage conditions that can affect the fault current characteristics of the local network. Alternate contingency events are selected and studied to ensure correct relay operation for a wide range of system configurations. In this case, the focus is not on equipment ratings; rather, it is on secure protection system operation. As the penetration of BPS-connected inverter-based resources as well as DERs continue to increase, their impact on 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. In each scenario in **Table 4.1**, TPs, PCs, and TOs are recommended to establish short-circuit data collection requirements for existing and future DER additions to assure studies can be performed adequately.

[65] "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.[66] 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 is still affecting fault characteristics[67] 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., 1547-2018). Existing and future installations of DERs may not provide fault current unless momentary cessation is prohibited by local requirements.[68] 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).[69] 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 so long as any significant differences in fault current contribution is differentiated. TPs and PCs will need to assess the potentiality of this scenario and determine whether they should proactively collect aggregate DER data for short-circuit modeling.

[66] 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.
[67] Decreasing fault current magnitude and the uncertain phase angle relationship between voltages and currents from inverter-based resources
[68] This will need to be analyzed closely and coordinated between distribution and transmission planning and protection engineers.
[69] 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 BESSs). Inverter-based DERs may only provide a relatively small fault current (i.e., on the order of 1.1 pu maximum) if any. IEEE 1547-2018 allows for the use of momentary cessation during low voltages such as during fault events, and, therefore, fault current from DERs may very well be minimal or zero in the future. This type of information should be considered by the TP and PC performing short-circuit studies.

Example Impact of Aggregate DERs on BPS Fault Characteristic

Whether or not a specific DER (i.e., U-DERs) or aggregate amount of DERs (i.e., R-DERs as well as U-DERs) have a significant[70] 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:[71]

- 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 where the DERs (and end-use loads) are directly being served out of 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, even 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.

[70] The term “significant” is used loosely and generally in this discussion but becomes increasingly important under higher penetrations of DERs.
[71] 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.

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[72] DERs:[73]

- 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)[74] 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).

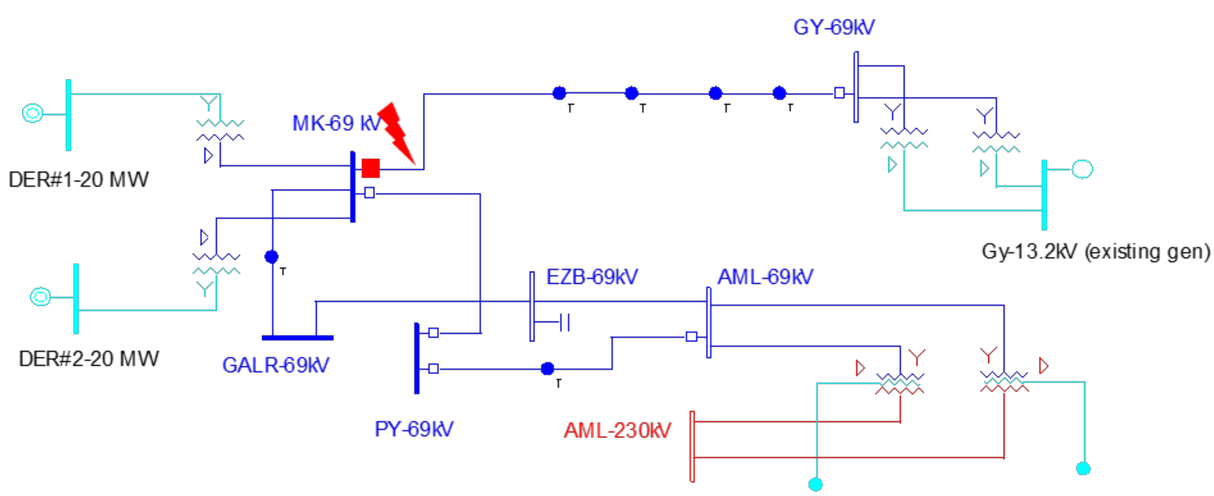

Figure 4.1: Example Network for Breaker Underrating Example

[72] Again, this is likely on a T-D transformer basis, per TP and PC data reporting requirements.
[73] Based on minimum requirements for modeling voltage-controlled current sources in short circuit programs
[74] These may include sub-transient, transient, and other applicable time frames based on TP and PC modeling and study techniques.

Chapter 5: GMD Data Collection Requirements

NERC TPL-007-3[75] requires TPs, PCs, TOs, and Generator Owners owning facilities that include power transformers with a high-side, wye-grounded winding with terminal voltage greater than 200 kV to perform GMD vulnerability analysis. The GMD vulnerability assessment is a documented evaluation of potential susceptibility to voltage collapse, cascading, and localized damage to equipment due to GMD events.[76]

During a GMD event, quasi-dc GICs flow through transmission circuits and return through the Earth by grounded-wye transformers and series windings of autotransformers that provide a dc path between different voltage levels. DC current flow through transformers produces harmonic currents that can increase transformer reactive power consumption and may cause hot-spot heating that potentially leads to premature transformer loss of life or failure. Furthermore, harmonic currents propagate through the power system can cause BPS elements to trip and may be a potential susceptibility for aggregate DER tripping.[77]

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.[78] 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 to higher levels, 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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75 https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=TPL-007-3&title=Transmission%20System%20Planned%20Performance%20for%20Geomagnetic%20Disturbance%20Events&jurisdiction=United%20States

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

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

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

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.[79] 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.[80] If industry is moving towards performing EMT simulations for BPS-connected plants (for example, on the order of 50 MW) because of known reliability issues, it warrants similar EMT simulations to be performed for pockets of high penetrations of DERs as well (for example, a small geographic area of 50–100 MW of DERs). This chapter describes the 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 the localized penetration of these resources is high. Examples of situations where these types of studies are needed include, but are not limited to, the following:

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

[79] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_IBR_Interconnection_Requirements_Improvements.pdf
[80] 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. 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.[81]

Mapping TP and PC Modeling Needs to DER Data Collection Requests

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

- **R-DER:** Small, retail-scale DERs across the distribution system (e.g., rooftop solar PV) will most likely not have DER models or information available, 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, 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
  - Reasonably replicate, to the ability of the model, the per-phase nature of DER functions
- **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.

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 appropriately identify specific reliability issues in high DER penetration pockets; therefore, the TP and PC should coordinate with the DP or other external entity to gather EMT modeling information to the extent possible, when needed.

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

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Appendix B: Data Collection for DER Energy Storage

Collecting data for DER energy storage is similar to collecting data for DER generating resources. However, it is worthwhile to highlight considerations that should be made when developing data reporting requirements for collecting DER data that ensure clarity for representing energy storage for planning assessments. This appendix describes some of the considerations at a high level that should be made and also describes specific data points that are unique to energy storage from a data collection standpoint. While there are many types of energy storage technologies available today, this appendix focuses mainly on inverter-based battery energy storage since it is the most prominent form of DER expected in the foreseeable future and widely observed in DER Interconnection queues today. Existing large, synchronous DERs may need to be modeled explicitly based on TP and PC modeling practices, and the TP and PC should have these considerations listed in any modeling requirements. Note that 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 be able to make appropriate modeling decisions based on their own practices.

Considerations for Steady-State Modeling

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

- **Location:** TPs and PCs will need to know the general location (at least mapped to a T-D transformer) of energy storage batteries such that they can be modeled appropriately in planning base cases in conjunction with other DERs and end-use loads. Separating DER generation and energy storage for collecting accurate DER data from the DP in coordination with any other state-level agency or regulatory body is a prudent step for effectively developing base cases based on TP and PC practices.
- **DER Type (or aggregate type):** As stated, differentiating out DER generators, DER energy storage, and hybrid facilities will be needed for the purposes of aggregate modeling of DERs in the future.
- **Transformer Information:** If the energy storage DER is represented as a U-DER, a generator step-up transformer may be explicitly modeled by the TP and PC based on their modeling practices.[82] 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. Therefore, some information will be needed on energy storage DER output profiles. Some questions for consideration include, but are not limited to, the following:
  - What percentage of energy storage DERs are participating in wholesale markets, and can the markets in which those DERs are participating provide any useful information in terms of how the energy storage DERs may be dispatched?

[82] 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, various 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. Therefore, it is not likely that additional information would be needed for energy storage DERs.
- **Minimum DER active power capacity (Pmin):** Energy storage resources have the ability to charge (unlike DER generators), 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. Knowing this information, TPs and PCs will be able to model them accordingly.
- **Maximum DER reactive power capability (Qmax and Qmin):** If energy storage DERs are providing any voltage support, these resources will need an associated Qmax and Qmin value in the base case, and the DP will need to coordinate with the TP and PC to understand appropriate assumptions.

Considerations for Dynamics Modeling

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

- ***Typeflag*:** Explicit modeling of energy storage DER requires consideration of the *typeflag* parameter of the DER_A dynamic model. Refer to software model specifications for how to set *typeflag* to emulate an energy storage device.[83]
- ***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 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; however, this is not likely in most

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

cases once 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 requirements are in place for DER energy storage versus DER generation regarding voltage control. Voltage control settings that differ across DER energy storage and generation may require modeling details where additional data may be required by the TP and PC.

Considerations for Short-Circuit Modeling

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

Considerations for GMD Modeling

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

Considerations for EMT Modeling

EMT modeling considerations for energy storage 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 accounting of 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,[84] the Minnesota Public Utilities Commission,[85] 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 process of DER data collection. In particular, TPs and PCs will likely benefit by establishing data specifications that leverage the respective strengths of both DPs and DER installers for existing facilities as well as other sources for forward-looking projections. Furthermore, DPs could establish requirements that require DER installers to provide information to the DP, TP, and PC during DER interconnections. DPs may consider working with state regulators and other agencies to determine the most effective method for establishing these types of requirements. If alternative sources of DER data are readily available in higher quality forms for use by the TP and PC, these should be leveraged to the extent possible for use in planning BPS studies. Diagrammatic examples accompanying data specifications will likely reduce any confusion or misunderstanding between entities. Collaborative processes by which data specifications are determined and data collection frameworks are designed will likely result in higher quality information transferred from the DP and other applicable external entities to TPs and PCs. Higher quality information for the purposes of modeling will support reliable operation of BPS.

AEMO DER Registry Case Study

A recent example of external DER data that can be useful for modeling purposes comes from the Australian Electricity Market Operator (AEMO) DER Register.[86] 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.[87] 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).[88]

[84] https://ww2.energy.ca.gov/renewables/tracking_progress/documents/renewable.pdf

[85] https://mn.gov/puc/energy/distributed-energy/data/

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

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

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

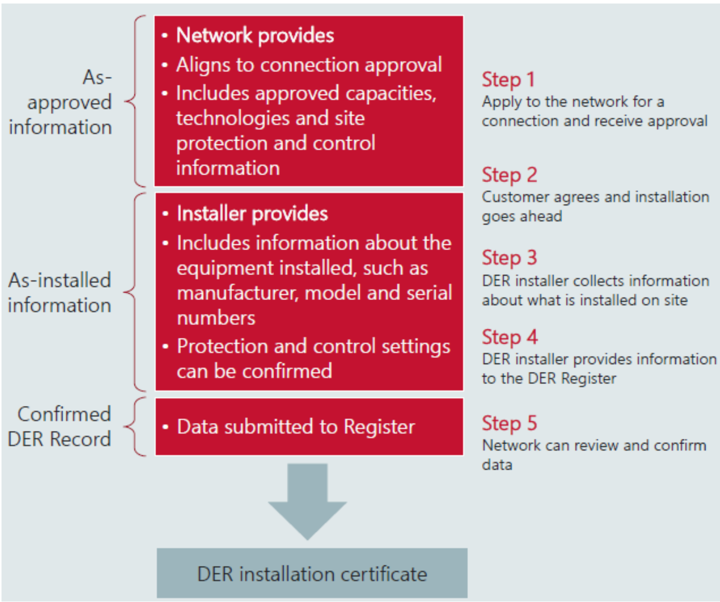

Figure C.2: Workflow of Joint Submission of DER Generation Data [Source: AEMO]

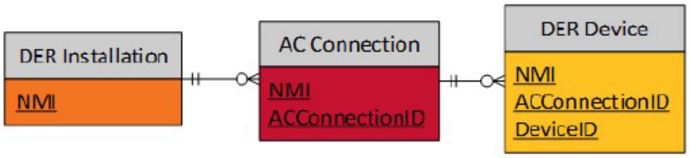

Figure C.3: Combination of DER Data as Defined by AEMO's Data Model [Source: AEMO]

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.[89] 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 principals, 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 connection approvals and data collection. As a result, AEMO's DER register system is designed with optionality to provide and validate DER data via API directly from the NSP, AEMO's web portal, or via smart-phone applications that many DER installers are already using to register an installation to access government subsidies. These options enable the minimum 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.[90]

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

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

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