

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Distributed Energy Resources

Connection Modeling and Reliability Considerations

December 2016

DRAFT

RELIABILITY | ACCOUNTABILITY



3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Table of Contents

Preface..... iii

Executive Summary iv

Introduction..... vi

Chapter 1: Definition of Distributed Energy Resources 1

Chapter 2: Reliability Considerations for DER 3

Chapter 3: Data and Modeling for DERs..... 6

 Data Requirements and Information Sharing at the T-D Interface 6

 DER Modeling for Bulk Power System Planning and Operations 7

 Steady-State Studies 9

 Dynamic Studies 11

Chapter 4: Characteristics of Non-Synchronous DERs 16

 Background 16

 Voltage Ride-Through (VRT) and Frequency Ride-Through (FRT) Characteristics and Consequences 17

 California Rules for DERs..... 20

Chapter 5: Previous Work of the NERC IVGTF Task Force..... 23

Chapter 6: NERC Reliability Standards 25

Chapter 7: Recommendations..... 27

Appendix A: Typical Connection of Distributed Energy Resources 28

Appendix B: Operations and Long-Term Planning 33

Appendix C: Review of Existing NERC Standards..... 37

Appendix D: Transmission-Distribution Interface 39

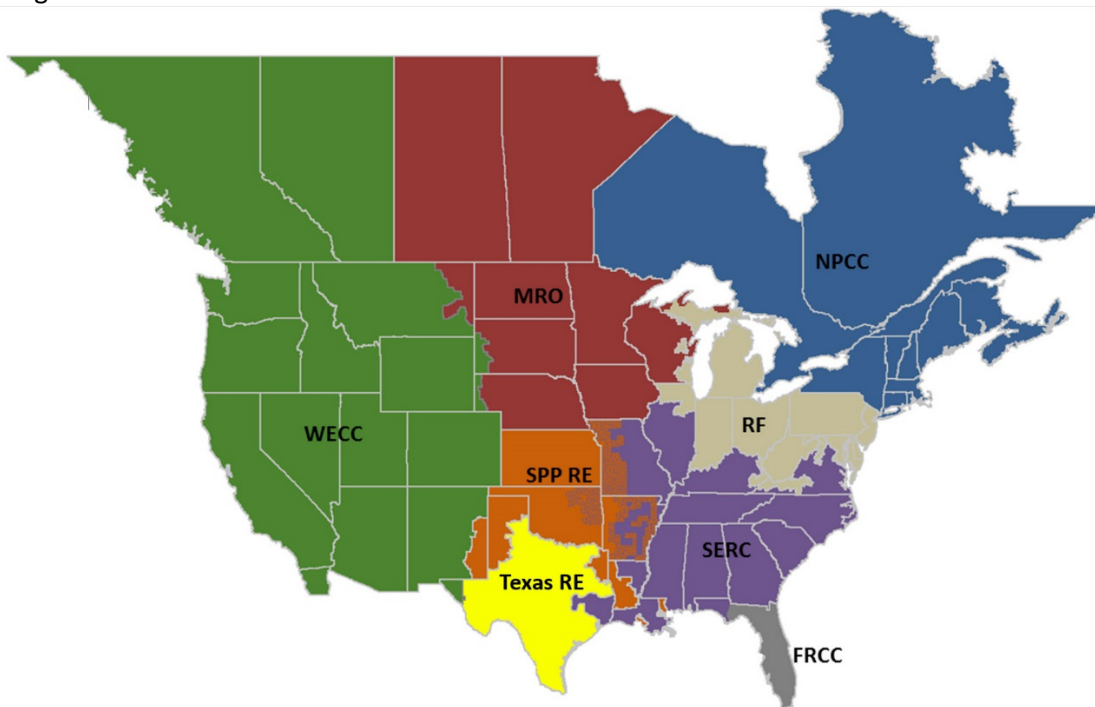
Task Force Membership 40

References 41

Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC’s area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC’s jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into eight Regional Entity (RE) boundaries as shown in the map and corresponding table below.



The North American BPS is divided into eight Regional Entity (RE) boundaries. The highlighted areas denote overlap as some load-serving entities participate in one Region while associated transmission owners/operators participate in another.

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool Regional Entity
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Executive Summary

The North American electric power system is transforming to a resource mix that relies less on coal and nuclear while integrating more natural gas, wind, solar, distributed generation, and demand response resources. The NERC Essential Reliability Services (ERS) Working Group is studying this transformation in the broader context of monitoring grid reliability and resiliency. Additionally, as noted in the [ERS Framework Report](#) in 2015, Distributed Energy Resources (DERs) are a rapidly growing part of this transformation. This report discusses the potential reliability risks and mitigation approaches for increased levels of DERs on the bulk power system (BPS).

At the distribution level, the potential impacts of DERs are fairly well understood in the industry. The translation of these impacts to the BPS has received less study. This report discusses the challenges as well as the steps forward for reliably integrating higher DER penetrations.

In certain areas, DERs are numerous and embedded within a distribution system that has traditionally been viewed as a relatively passive load resource on the BPS. This will no longer be a valid assumption as we integrate more DERs on the electric system. In addition, newer DER technologies are capable of providing advanced support services that will be needed as we transition from conventional synchronous resources to non-synchronous inverter-based resources. It is incumbent upon NERC and the industry to understand DER functionality and develop a set of guidelines to assist in modeling and assessments, such that owners/operators of the BPS can evaluate and model DERs in the electric system. Data requirements and sharing of information across the transmission-distribution (T-D) interface should also be further evaluated to allow for adequate assessment of future DER deployments.

This report does not mean to suggest that DERs are less capable than conventional resources in supporting the reliable operation of the BPS. DERs will increasingly have state-of-the-art capabilities for active power control and reliability services. However, there are differences in how DERs are deployed within the grid and the characteristics of the services and responses that they provide, so these differences must be understood and modeled appropriately. This report is a first step toward understanding how practices for modeling and operating the BPS may be enhanced to reflect future system characteristics. Improvements to DER interconnection standards, such as proposed changes to the Institute of Electrical and Electronics Engineers IEEE 1547, will assist in addressing potential impacts of higher DER penetration.

The ability to accurately model the power system is important given the highly complex and interconnected nature of the power grid. System modeling is critical for power grid operations and planning for both normal operations and disturbances to ensure reliable operation of the BPS. All components of the system must be represented in the models, either directly or in an aggregated way, with sufficient fidelity to enable the model to provide meaningful and accurate simulations of actual system performance. A modular approach to represent DERs in BPS studies, with some level of data validation, may ensure accurate representation of the resources for the specific BPS study type. While dynamic models for different DER technologies are available, limited existing knowledge and experience of modeling DERs in system planning studies and operating with higher levels of DER will require future collaborative research, knowledge exchange and learning.

Improvements to modeling will require some level of data for DER generation separated from load (even when both are “behind the meter”). For modeling purposes, generation from DERs should not be netted with load as penetration increases. This is quite distinct from tariff and ratemaking issues (e.g., net metering, time-of-use rates, value of solar methods, etc.). Data for DER modeling and verification purposes must be collected by some entity, perhaps the Distribution Provider (DP), and become available at suitable granularities to correspond to the future BPS modeling needs. There are many options for what entity this could be, and this may vary depending on the state or region, but such data will be increasingly important to support critical modeling for both planning and operations.

The ERS Working Group has also discussed the importance of continuously maintaining the balance between demand and generation for the Balancing Area. These ramping and balancing activities may become more challenging for regions with high levels of DERs, as these activities will not only be required to include those resources located on the BPS, but also on the distribution system, which currently may not be visible or controlled by the BPS operator.

A coordinated effort by transmission and distribution entities is needed to determine appropriate use of future DER capabilities. Some DERs have capabilities to ride through disturbances, contribute reliability services and follow dispatch signals. These capabilities are starting to be used either directly or through aggregators for a number of emerging services (e.g., demand response, microgrids, virtual power plants, etc.). This report does not mean to suggest that DER must be dispatched like conventional generators or utility-scale variable energy resource power plants, but methods and technologies for active power control and reliability services from some portion of DERs and loads will likely be important in the future, and the transmission and distribution utilities will need to coordinate actions to meet BPS reliability needs while minimizing the distribution impact.

Introduction

The generation mix is undergoing a transition from large, synchronously connected generators to generators that use more natural gas, renewable energy, and demand response. The growing interest in a more decentralized electric grid and new types of distributed resources further increases the variety of stakeholders and technologies. Both new and conventional stakeholders are building or planning to build distributed solar photovoltaic systems, energy management systems, microgrids, demand services, aggregated generation behind the retail meter, and many other types of distributed generation. Many of these stakeholders have considerable experience with installing such systems on the distribution network for the benefits of industrial or residential customers, but may have less familiarity with the bulk power system (BPS) and the coordinated activities that ensure system reliability during both normal operation and in response to disturbances. While this report examines reliability considerations from the viewpoint of the BPS, it will also help distributed energy resource (DER) providers understand the reliability considerations for the power system as a whole.

Increasing amounts of DERs can change how the distribution system interacts with the BPS and will transform the distribution system into an active source for energy and essential reliability services (ERSs). Attention must be paid to potential reliability impacts, the time frame required to address reliability concerns, coordination of ERSs and system protection considerations for both the transmission and distribution system, and growing importance of information sharing across the transmission-distribution (T-D) interface.

Today, the effect of aggregated DERs is not fully represented in BPS models and operating tools. This could result in unanticipated power flows and increased demand forecast errors. An unexpected loss of aggregated DER could also cause frequency and voltage instability at sufficient DER penetrations. The system operator typically cannot observe or control DERs, so variable output from DERs can contribute to ramping and system balancing challenges.

This presents challenges for both the operational and planning functions of the BPS. In certain areas, DERs are being connected on the distribution system at rapid pace, sometimes with limited coordination between DER installation and BPS planning activities. With the rapid rate of DER installations on distribution systems, it will be necessary for the BPS planning functions to incorporate future DER projections in BPS models. These changes will affect not just the flow of power, but also the behavior of the system during disturbances. It is important to coordinate the planning, installation, and operation of DERs in relation to the BPS as we transition to a new resource mix.

The Essential Reliability Services Working Group (ERSWG) created the Distributed Energy Resources Task Force (DERTF) in 2016 to examine the reliability considerations from the integration of higher levels of DERs. This report is the result of this one-year effort by the DERTF.

Because information and modeling is so critical to the planning of a reliable BPS, after defining DERs (Chapter 1) and discussing general reliability considerations (Chapter 2), the DERTF focused primarily on how DERs are modeled (Chapter 3), the ride through response of DERs in the event of grid disturbances (Chapter 4), past NERC reports that are relevant (Chapter 5), and how NERC standards deal with the exchange of information that is needed for reliability purposes (Chapter 6). The DERTF recommendations are then summarized in Chapters 7.

Additional operational considerations of DERs are discussed briefly in Appendix B but were not fully developed in the scope of the DERTF. The transformation of the distribution utility has become a major topic of discussion in the industry, with many different operational and business models for the future distribution utility under consideration. It will be important for NERC's ERS effort to follow this transformation and consider the implications and responsibilities for ensuring reliability with higher DER penetrations.

Chapter 1: Definition of Distributed Energy Resources

In undertaking the review of DERs, NERC understands that various definitions have been used within the industry. However, the DERTF believes it is important to establish a working definition to create the context for the discussions within the report. While more detail is provided below, this general definition is a useful starting point:

A Distributed Energy Resource (DER) is any resource on the distribution system that produces electricity and is not otherwise included in the formal NERC definition of the Bulk Electric System (BES).

As developed by NERC and approved by FERC, the BES definition includes all the larger elements and facilities that are necessary for the reliable operation and planning of the interconnected bulk power system (BPS). With the growing prevalence of DERs, some regions are recognizing that the locations and characteristics of the DER devices must be correctly represented in planning, operating and stability models to achieve accurate results. Understanding DER is therefore becoming an important consideration for BPS reliability.

For a more formal description of DERs that shows how they fit with other existing definitions in the NERC functional model, the DERTF also offers the definition shown below. Based upon research and discussions within the industry, it is hoped that these definitions represent a common set of interests and a framework for moving forward with an improved understanding of the role of DER in the context of BPS reliability.

DERs include any non-BES resource (generating unit, multiple generating units at a single location, distributive generator, energy storage facility, microgrid, etc.) located solely within the boundary of any distribution utility, Distribution Provider, or Distribution Provider-UFLS Only, including:

- **Distribution Generation (DG):** Any non-BES generating unit or multiple generating units at a single location owned and/or operated by 1) the distribution utility, or 2) a merchant entity.
- **Behind The Meter Generation (BTMG):** A generating unit or multiple generating units at a single location (regardless of ownership), of any nameplate size, on the customer's side of the retail meter that serve all or part of the customer's retail Load with electric energy. All electrical equipment from and including the generation set up to the metering point is considered to be behind the meter. This definition does not include BTMG resources that are directly interconnected to BES transmission.
- **Energy Storage Facility (ES):** An energy storage device or multiple devices at a single location (regardless of ownership), on either the utility side or the customer's side of the retail meter. May be any of various technology types, including electric vehicle (EV) charging stations.
- **DER aggregation (DERA):** A virtual resource formed by aggregating multiple DG, BTMG or ES devices at different points of interconnection on the distribution system. The BES may model a DERA as a single resource at its "virtual" point of interconnection at a particular T-D interface even though individual DER comprising the DERA may be located at multiple T-D interfaces.
- **Microgrid (MG):** An aggregation of multiple DER types behind the customer meter at a single point of interconnection that has the capability to island. May range in size and complexity from a single "smart" building to a larger system such as a university campus or industrial/commercial park.
- **Cogeneration (see NERC definition):** Production of electricity from steam, heat, or other forms of energy produced as a by-product of another process

- **Emergency, Stand-by, or Back-up generation (BUG):** A generating unit, regardless of size, that serves in times of emergency at locations providing basic or elemental needs of the customer or distribution system. This definition only applies to resources on the utility side of the customer retail meter.

While defining DER is an important first step, to fully understand the potential interaction of these resources with the BPS, it is essential to recognize how these resources are interconnected to the power grid. DERs, as defined above, are generally interconnected to a Distribution Provider's electric system at the primary voltage (≤ 100 kV but > 1 kV) and/or secondary voltage (≤ 1 kV). As such, the effect of aggregated DERs is not fully represented in BPS models and operating tools. A discussion and examples of the types of interconnections between DERs and the BPS are provided in Appendix A. Understanding how these resources are defined by NERC and how they are interconnected to the BPS allows for further exploratory discussions on how to model DERs and their current operating characteristics.

For the purposes of this report, DERs are defined as resources that produce electricity. Demand side management (DSM) resources are not currently included in the definition, but the task force continues to discuss the appropriate treatment of DSM when it comes to the aggregate characteristics, modeling requirements, and potential BPS reliability impacts at the T-D interface. As shown in Appendix D, while DSM activities may not have the same characteristics or behaviors as resources that produce electricity, DSM activities can have impacts at the T-D interface that overlap and interact with those of DERs. As such, the task force recommends future consideration of DSM in the DER definition and how the recommendations of this report may be applied to DERs and DSM resources in a unified way.

Chapter 2: Reliability Considerations for DER

In certain areas, North America is experiencing a growing interest in a more decentralized electric grid with increasing penetrations of DERs. Greater levels of these interconnected resources reinforce the need to ensure the reliability of the BPS during both normal operation and in response to disturbances. Increasing amounts of DERs can change how the distribution system interacts with the BPS and may transform the distribution utility into an active source for both energy and ERSs. These dramatic changes for the distribution system, which can alter not just the flow of power but also the responses to various types of disturbances, must be understood and represented in the planning and operation of the grid. This can be accomplished through coordinated activities that ensure effective communication is occurring between those operating the BPS and the Distribution Provider.

The following is an examination of the current state of DERs in today's BPS:

1. **Modeling:** DERs are typically netted with load at the distribution bus for operations and planning. The challenge is to understand their variability and interactions with other resources. The electric industry has studied and incorporated the characteristics of conventional resources into the models that are used for planning and operations. To support the reliable integration of DERs at higher levels, appropriate modeling methods will be necessary.
2. **Ramping and Variability:** Certain types of DERs create significant ramps, such as morning and evening solar ramps, which are different than historically experienced by the distribution system and the BPS. It is important to coordinate the planning, installation, and operation of resources as we transition to a resource mix with changing characteristics of DERs, loads and other generation on the BPS.
3. **Reactive Power:** Currently, most DERs are not required to provide reactive support to help control local voltage levels. Modern technologies, including inverters for new rooftop solar PV installations, should have the capability to support voltage and ride through voltage excursions. Use of these capabilities will be increasingly important to support the reliability of both the transmission and distribution systems.
4. **Frequency Ride-Through:** DERs are not coordinated with the voltage and frequency ride-through requirements of NERC Standard PRC-024-2. As DERs are added to the system, frequency and voltage ride-through capabilities become important and must be considered both locally and for the BPS.
5. **System Protection:** DERs are not coordinated with under-frequency load shedding programs, nor are they used to calculate the Most Severe Single Contingency and contingency reserve requirements. High levels of DERs with inverters can also result in a decline in short circuit current, which can make it more difficult for protection devices to detect and clear system faults. Hence, the implications of DERs as part of system protection must be taken into consideration while planning the BPS and distribution systems.
6. **Visibility and Control:** Many DERs are passive in that they do not follow to a dispatch signal and are generally not visible to the system operator. The lack of visibility and control is not only a challenge for operations, but must also be accounted for in the planning of the BPS. At higher penetration levels, DER capabilities related to visibility and control may become increasingly important.
7. **Load and Generation Forecasting:** Currently, DERs are modeled as load modifiers for most load forecasting tools. However, given the number of DER installation applications and projections of future growth, it may become important to have sufficient information to support forecasting of DER power production separately from load, as well as to consider future DER deployment scenarios in the planning of both the distribution systems and the load/generation forecasting systems.
8. **Interconnection Requirements:** Interconnection requirements are evolving with increasing DER penetrations, and as a consequence of this, a number of DER classes with very different dynamic behaviors will exist in the BPS. It will be important to know this information, at least in an aggregate way, so that the dynamic characteristics can be modeled correctly for BPS planning.

9. **Reliability Standards:** NERC and industry must consider the existing standards, functional model, and related equipment standards in terms of accommodating the growing integration of DERs while ensuring prudent planning and reliable operation of the BPS.

DERs and Potential Risks to Reliability

At low penetration levels, the effects of DERs may not present a risk to BPS reliability. However, as penetrations increase, the effect of these resources can present certain reliability challenges that require attention. This leads to areas where further consideration is needed to better understand the impacts and how those effects can be included in planning and operations of the BPS.

The DERTF believes that data on installed and projected DER units, at least in an aggregated form at the transmission-distribution (T-D) interface, is needed for reliability modeling purposes. Important data for modeling include information on the location, type, size, configuration, interconnection characteristics, disturbance response characteristics, and date of operation of the equipment. DER generation profiles would also improve the fidelity of modeling results rather than forcing models to assume worst-case scenarios. It is particularly important that both data and models be available down to the elements of interest to the models (e.g., separating the DER generation from the load).

The ERSWG has also discussed the importance of continuously maintaining the balance between demand and generation for the Balancing Area. These ramping and balancing activities may become more challenging for regions with high levels of DERs and variable energy resources (VERs). Utility-scale VERs (such as solar and wind) are now required to ride through disturbances, provide reliability services, and have active power management capability to respond to dispatch or automatic generation control (AGC) signals. Many DERs will also have such capabilities, and these capabilities may be used either directly or through aggregators for numerous emerging services (e.g., demand response, microgrids, virtual power plants, etc.).

System operators require sufficient levels of ERSs from online resources for the reliable operation of the BPS. It is not necessary that all resources provide all services at all times, but if conventional resources are offline or replaced by DERs, it may be increasingly important to use DERs for active power control and essential reliability services. The DER Task Force is not suggesting that DERs be dispatched like conventional generators or utility-scale VER power plants, but methods to obtain active power control and reliability services from some portion of DERs are likely to be important in the future.

Current work on enhancements to the IEEE 1547 interconnection requirements and how capabilities of DERs are used will present opportunities for improving BPS reliability. Technology advances have the potential to alter DERs from a passive “do no harm” resource to an active “support reliability” resource. From a technological perspective, modern DER units will be capable of providing essential reliability services and supporting BPS reliability. These technologies are likely to become more widely available in the near future, and they present an opportunity to enhance BPS performance when applied in a thoughtful and practical manner. For example:

- When viewed in aggregate, multiple DER units can scale up to become a very large resource. For example, in 2016, California Independent System Operator (CAISO) states there is 4,900 MW of DERs in its Balancing Authority. This is its largest single resource when aggregated. If DERs could provide frequency response on a 5% droop characteristic, it could provide 163 MW / -0.10 Hz of frequency response to CAISO. This is a significant benefit.
- With respect to voltage support, active voltage control on a feeder circuit could significantly lower the risk of fault induced delayed voltage recovery (FIDVR) events for multiphase faults on the transmission system. By reducing net load on the feeder and providing voltage support, these events related to locked rotor current of single-phase compressors following a fault would have a reduced effect on the distribution voltage and BPS voltage levels.

- With the possible aggregation of DER capabilities, it becomes feasible to “dispatch” DERs for system balancing, demand response, operating and contingency reserves, or to mitigate ramp rate concerns in the morning and evening.

The capabilities of DERs are evolving rapidly, so there are a number of emerging topics that are not within the scope of this report. For example, protection settings are a future step in the modeling efforts that are discussed in Chapter 3, and IEEE 1547 proposals currently deal with reenergizing but not with DER capabilities for use as a black start resource. NERC should continue to monitor and participate in the ongoing evolution of capabilities and how such capabilities should be incorporated into future planning and operating of the BPS.

Chapter 3: Data and Modeling for DERs

The increasing amount of DERs connected to the distribution system requires consideration of DER resources in the planning and operations of the BPS. A key takeaway for both planning and operating considerations is the collection and sharing of data across the transmission-distribution (T-D) interface.

The scope of this chapter covers the recommended data requirements followed by the details around appropriate modeling for (a) steady-state power flow and short-circuit studies, and (b) dynamic disturbance ride-through and transient stability studies for BPS planning. Distribution system aspects (e.g. distribution protection and planning), BPS small-signal stability, and BPS operational aspects such as flexibility and ramping are out of the scope of this document.

Data Requirements and Information Sharing at the T-D Interface

With DERs being connected at the distribution level but having potential impact at the BPS level, the following data and information sharing recommendations across the T-D interface are important to support adequate modeling and assessment of BPS reliability issues:

1. DER data in an aggregated way for each substation, including data to represent the mix of DERs and their capabilities.
 - a. DER type (i.e. PV, wind, cogeneration, etc.)
 - b. DER MVA rating
 - c. Relevant energy production characteristics (i.e., active tracking, fixed tilt, energy storage characteristics, etc.)
 - d. DER operating power factor and/or reactive and real power control functionality
 - e. DER point of common coupling (PCC) voltage
 - f. DER location: behind-the-meter / in-front-of-the-meter
 - g. Date that DER went into operation
2. A set of default equivalent impedances for various distribution grid types that can be used to choose adequate parameters for, e.g., WECC's PVD1 model for distributed PV systems.
3. Relevant interconnection performance requirements based on national or regional standards.
4. Distributed energy resources stability models and their voltage and frequency trip parameters. In particular the regionally specific parameters V_{t0} , V_{t1} , V_{t2} , and V_{t3} of WECC's distributed PV model (*PVD1*) [41].

The recommended data requirements should be considered by the Regional Committees and specified in Regional Criterion such as WECC's "Steady State and Dynamic Data Requirements MOD-(11 and 13)-WECC-CRT-1 Regional Criterion" [5] and others.

DER Modeling for Bulk Power System Planning and Operations

While it may be desirable to model DERs in all planning studies and in full detail, the additional effort of doing so may only be justified if DERs are expected to have significant impact on the modeling results. An assessment of the expected impact will have to be scenario-based and the time horizon of interest may vary between study types. For long-term planning studies, expected DER deployment levels looking 5-10 years ahead may reasonably be considered. Whether DERs are modeled in BPS studies or not, it is strongly recommended that the minimum data collection of DER interconnections be established in order to adequately assess future DER deployments.

Modeling modern bulk systems with a detailed representation of a large number of DERs and distribution feeders can increase the complexity, dimension, and handling of the system models beyond practical limits in terms of computational time, operability, and data availability. Therefore, a certain degree of simplification may be needed, either by model aggregation (i.e., clustering of models with similar performance), by derivation of equivalent models (i.e., reduced-order representation), or by a combination of the two. Netting of DERs with loads at the substation level is not recommended for high DER penetration scenarios because the resulting models will misrepresent potential aggregate impacts of DERs on BPS power flows and dynamic performance.

A *modular approach* to represent DERs in BPS studies as illustrated in Figure 1 is recommended to ensure accurate representation of the resources for the specific BPS study type. The hierarchy of the clustering of DERs for model aggregation could consider:

- Differentiation of DERs per resource type to derive meaningful dispatch scenarios rather than worst-case dispatches for BPS planning studies.
- Differentiation of DERs per interconnection requirements performance (i.e. the adhering interconnection standard requirements) to represent the fundamentally different steady-state and dynamic behavior among future and legacy DERs.
- Differentiation of DERs per technology-type (e.g., inverter-coupled versus directly-coupled synchronous generator DERs) to accurately represent the technology-specific dynamic behavior.

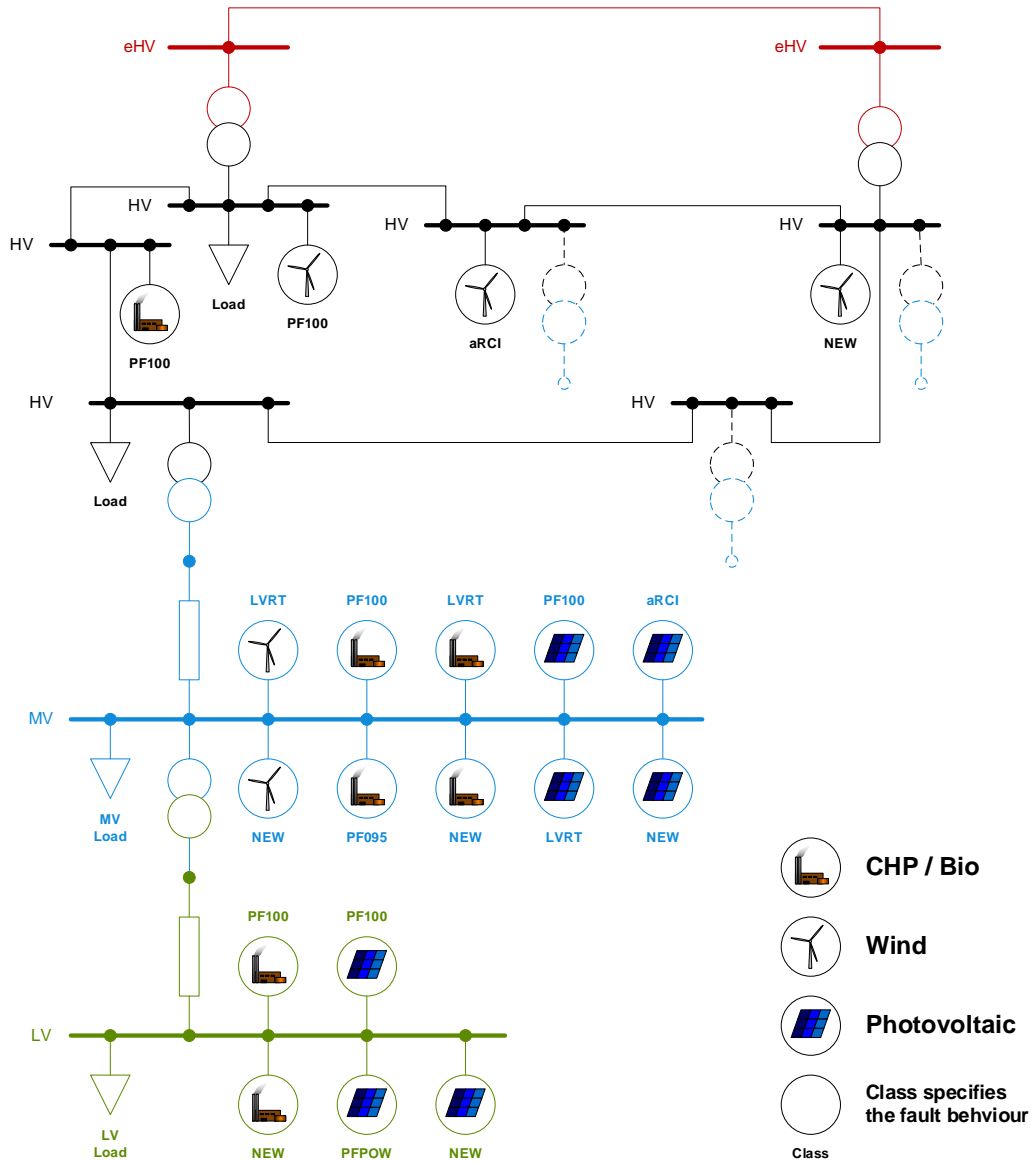


Figure 1: Modular representation of Distributed Energy Resources in BPS steady-state and dynamic studies. [1; 2]

Defining the appropriate balance between model accuracy and simplicity of steady-state and dynamic equivalent models for DERs is a major objective of ongoing research efforts. However, certain guidelines for DER modeling have been published. The following includes a synopsis of the industry guidelines issued by the Western Electricity Coordinating Council (WECC). Aggregated and/or equivalent modeling of DERs is discussed for four types of bulk power system planning studies:

1. Steady-state power flow studies
2. Steady-state short-circuit studies
3. Dynamic disturbance ride-through studies
4. Dynamic transient stability studies

Data requirements were summarized at the start of this chapter. The limited existing knowledge and experience on modeling DERs in BPS planning studies will require ongoing research, knowledge exchange, and learning.

Steady-State Studies

Steady-state studies aim at:

- a. Power flow calculation to determine BPS real and reactive power flows for network expansion planning, voltage stability studies and coordination of voltage controls at the T-D interface, and
- b. Short-circuit calculations to determine short-circuit power levels for equipment rating and voltage sag propagation analysis.

Modeling of DERs in these studies would consider the real power injection at distribution system level and the reactive power that may be supported or required by DERs. A power flow case is also needed to initialize the state variables of a dynamic BPS model for a dynamic stability study.

Steady-State DER Models

Appropriate DER models are required and may differ between the steady-state study types. Steady-state power flow calculations may only require a standard generator or simplistic voltage or current source models with voltage control loops appropriate for steady-state analysis under normal conditions of voltage and frequency.

Steady-state short-circuit studies require appropriate DER models that would adequately represent the short-circuit contribution from DERs. Inverter-based DERs are current and power limited sources. A current-limited Norton equivalent with control loops that adequately model the response under abnormal conditions of voltage is required. The short-circuit contribution of DERs depends significantly on the performance specified by interconnection requirements, such as trip and ride-through requirements. Traditional steady-state short-circuit analysis algorithms are not suitable for inverter-based DERs. New algorithms that iteratively calculate the current-limited short-circuit contributions from inverter-based DERs may be needed.

Aggregated Modeling and Netting of DERs with Load

In most existing BPS planning studies, the distribution system load is aggregated at the transmission buses and netted with generation on the distribution system (DER generation is treated as negative load). In those study cases and grid regions where DER levels are expected to significantly impact power flows between the transmission and distribution system to the point that they may conflict with NERC system performance criteria (e.g., NERC TPL-001-4 [3]), DERs should not be netted with load but modeled in an aggregated and/or equivalent way to reflect their dynamic characteristics and steady-state output. Exceptions for permissive netting of DERs (not explicitly modeling DERs but reducing load by DER generation based on explicitly available DER data) may be acceptable in steady-state studies for those DERs that inject real power only at unity power factor without the ability of providing static voltage support at low DER penetration levels.

Depending on the study region, the aggregate DER penetration at substation level, regional level, or interconnection-wide level may give indication towards the expected impact of DERs on the system performance; the decision to aggregate DERs, however, must always be system-dependent. This assessment should be irrespective of whether it is behind-the-meter DERs or before-the-meter (utility-scale) merchant DER.

While netting of DERs with loads at substation level should be discontinued in the future, existing guidelines do not require modeling of all DERs as a way to limit the complexity of the system model and data requirements. For example, the WECC manual and data [4; 5] only require:

- a. Modeling of any single DER with a capacity of greater than or equal to 10 MVA explicitly, and
- b. Modeling of multiple DERs at any load bus where their aggregated capacity at the 66/69 kV substation level is greater than or equal to 20 MVA with a single-unit behind a single equivalent (distribution) impedance model as shown in Figure 2 based on WECC's "PV Power Plant Dynamic Modeling Guide" [6].

The threshold above which DERs are not netted with loads is system-specific and may depend on the study specifications, DER penetration level, and load composition. For example, in the regional case of WECC, earlier versions of the WECC Data Preparation Manual stated that a maximum amount of five percent netted generation of an area’s total generation is recommended, but this statement was removed in the new version of the manual for use in 2017 [4]. In general, netting of DERs with loads should be avoided.

Minimum data collection for DER modeling should be established to enable adequate assessment of future DER deployments. Related data requirements are outlined in WECC’s “Steady State and Dynamic Data Requirements MOD-(11 and 13)-WECC-CRT-1 Regional Criterion” [5].

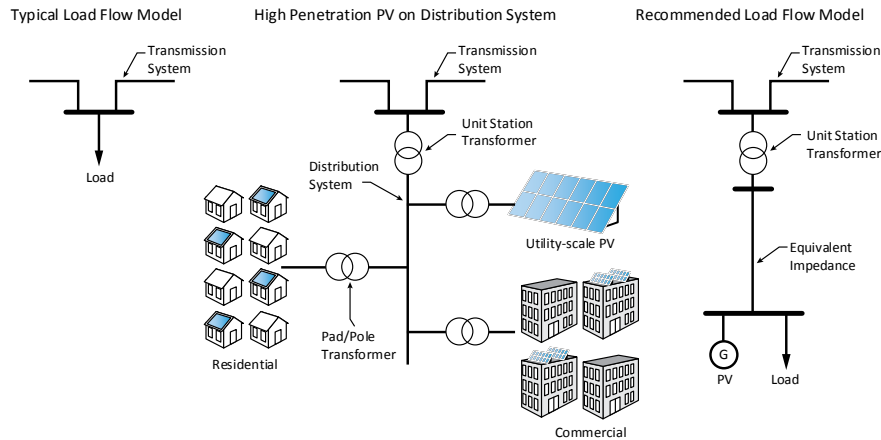


Figure 2: WECC recommended power flow representation for study of high-penetration PV scenarios. Source: EPRI figure based on [6].

More Detailed Representation in Special Cases

As stated earlier, the objective of modeling of DERs for power flow studies is to capture the effect of reactive power support as well as the voltage dependent characteristics of DERs in steady-state and dynamic simulations, particularly for voltage stability studies. The aggregation of DERs behind a *single* equivalent distribution impedance may be insufficient for steady-state studies in special cases.

The following special conditions may require detailed representation of the distribution system, either through considering the *multiple* equivalent impedances of High Voltage to sub-transmission lines as well as Medium Voltage to primary and Low Voltage to secondary feeders separately [2] or through equivalent voltage control blocks in the equivalent DER generator model:

1. Impactful penetrations of DER generation that operate at power factors other than unity and/or implement other real or reactive power functionality dependent on system voltages or power flows.
2. Impactful DER penetrations in terms of their percentage of instantaneous interconnection-wide load.
3. A significant amount of reverse power flows from distribution substation to BPS level.
4. Substantial amounts of DERs connected at different voltage levels in a region.

Depending on the particular characteristics of the distribution systems and their level of uniformity in the study case, regionally-specific equivalent impedances and equivalent voltage control blocks in the equivalent DER generator model may be used (e.g., for urban, sub-urban and rural feeders) to accurately model the voltage at the equivalent DER model terminals.

In grid regions where DER performance requirements are *changing*, i.e., have been changed or are expected to change substantially in the future, *multiple* equivalent generators may be used for each DER generation in order to appropriately reflect the DER performance. Existing DER units (i.e., legacy DERs) are typically not upgraded to meet the latest performance requirements.

Dynamic Studies

Dynamic simulation studies aim at:

- a. Disturbance ride-through analysis to determine BPS frequency and voltage stability following normally-cleared or delayed-cleared transmission faults with consideration of the amount of DER power that may be tripped off-line during the disturbance due to under-voltage, over-voltage, under-frequency, and/or over-frequency protection, and;
- b. Transient stability analysis to determine BPS transient stability during and following normally-cleared or delayed-cleared transmission faults with consideration of fast reactive support from DERs that may improve the transient response of the overall system.

Modeling of DERs in dynamic BPS studies requires a solid understanding of DER performance based on both interconnection requirements (see Chapter 4) and technology-specific DER performance and control systems.

Interconnection Requirements

Interconnection requirements (also known as performance requirements) are differentiated by DER rated capacity in North America and by DER connection voltage level in Europe. For BPS stability studies, interconnection requirements determine a *performance framework* for the network fault response of individual DER units depending on their commissioning period, connection level or size, and sometimes technology type.

With regard to disturbance ride-through requirements, IEEE Std. 1547-2003 [7], FERC's SGIP/SGIA [8; 9], and the former CA Rule 21 [10] for North America and California in particular, have focused on distribution-level protection and safety centric requirements meant to quickly trip DERs offline as to not interfere with legacy distribution-level protection equipment and to avoid the formation of utility islands. These standards, procedures and state rules have been or are currently being revised for voltage and frequency ride-through [11–14] with a focus on providing BPS level ride-through support. Additional dynamic performance requirements for DERs, such as dynamic voltage support during and/or following network faults, may evolve in the future similar to the requirements for an additional reactive current injection during faults as in [15-16] for Germany.

Dynamic DER Models

With respect to wind and PV generation connected to the BPS (i.e., typically wind and PV power plants of 10 MVA or larger), the following state-of-the-art generic dynamic models exist:

- Wind: The WECC generic wind turbine generator model (primarily for use with BPS connected wind turbine generators, but could be used for DERs where detailed distribution models are developed) are documented in [17]. The IEC models are documented in IEC Standard 61400-27-1 [18]. It is noteworthy that differences do exist between the generic wind turbine generator models specified in the IEC standard and the WECC modeling guidelines. The IEC models include a more detailed representation of the dynamic performance of wind turbine generators during the fault period than the WECC models [19-21] and, therefore, seem to be more suitable for transient stability studies.
- Photovoltaic (PV): The first generation of generic models for PV plants, developed by the WECC Renewable Energy Modeling Task Force (REMTF), has been approved under the WECC Modeling and Validation Working Group [6; 22; 23]. These models can potentially be used for modeling DERs for situations where explicit detailed modeling of DERs is warranted. For the purposes of BPS studies, much of the distribution system and the DERs are represented as aggregated models. WECC has initiated and developed some

aggregated, and simplified, DER models for representing devices such as distributed PV [6]; however, discussions continue within the WECC REMTF to improve these models. Currently, there is no IEC standard on PV modeling.

- **Synchronous generator DER:** Modeling of large-scale directly-coupled synchronous generator (SG) and their excitation systems in power system stability studies is well established and widely accepted recommendations exist [24; 25]. Modeling of medium- to small-scale, low-inertia, distributed combined heat and power (CHP) plants is a less investigated field, although some older publications exist [26-28]. A relevant publication from recent years models the network fault response of a medium-scale diesel-driven synchronous generator [29].
- **Other electronically-connected resources:** Other non-synchronous resources, such as battery storage or voltage converter HVDC, may initially be represented by a generic inverter model if more specific models are not available.

Aggregated Modeling and Determining Dynamic Equivalence

Modeling of Distributed Energy Resources in dynamic BPS planning studies may require a certain degree of simplification to limit the data and computational requirements as well as the general handling of the BPS model. Model reduction could either be achieved by model aggregation (i.e., clustering of models with similar performance), by derivation of equivalent models (i.e., reduced-order representation), or by a combination of the two. However, equivalent models for DERs should have sufficient fidelity to accurately consider the two main challenges of:

- a. Non-uniform model parameters of the controllers of the various DERs in a distribution feeder, and;
- b. Considerable diversity of the terminal voltages of DERs connected at different locations of a distribution feeder.

With regard to spreading model parameters, the modeling should distinguish at least the DER performance mandated by interconnection requirements. This could either be achieved by using separate classes of DER models with each representing the amount of DERs that went into operation when a certain requirements were in place, or by equivalent modeling of a mixed population of ‘legacy’ and ‘modern’ DERs with a ‘partial tripping’ design parameter as it has been considered in WECC’s distributed PV (*PVD1*) model [6]. Consideration should also be given to regional under frequency load shedding (UFLS) and under voltage load shedding (UVLS) programs that may trip distribution feeders at the substation level and thereby supersede DER ride-through or trip settings.

Consideration for the diversity of the terminal voltages of DERs connected at different locations of a distribution feeder will be important to accurately model the dynamic response of DERs in the periphery region (annulus) of a voltage sag as illustrated in Figure 3 [2]. This is the area where the modeling accuracy of DERs may have a large impact on the simulation results in very high DER penetration studies, because:

- The annulus of the voltage sag can have a very large geographic extent.
- The number of DER units in this part of the system can become a significant part of the total number of regionally located DER units.
- Depending on the real and reactive power injection of DERs during fault ride-through operation based on the interconnection requirements, DERs can significantly influence the distribution system voltage and therefore the behavior of other DERs, legacy and otherwise.

As illustrated in Figure 3, the post-fault real power imbalance due to under-voltage tripping of DERs will be larger in the case shown in diagram (a) than in the case shown in diagram (b). Hence, the accurate modeling of the voltage contour that delineates all system nodes in the annulus of a voltage sag at transmission system level where

the retained voltage is smaller than the DER's under-voltage protection threshold is important to accurately determine how much DER generation may trip during a disturbance.

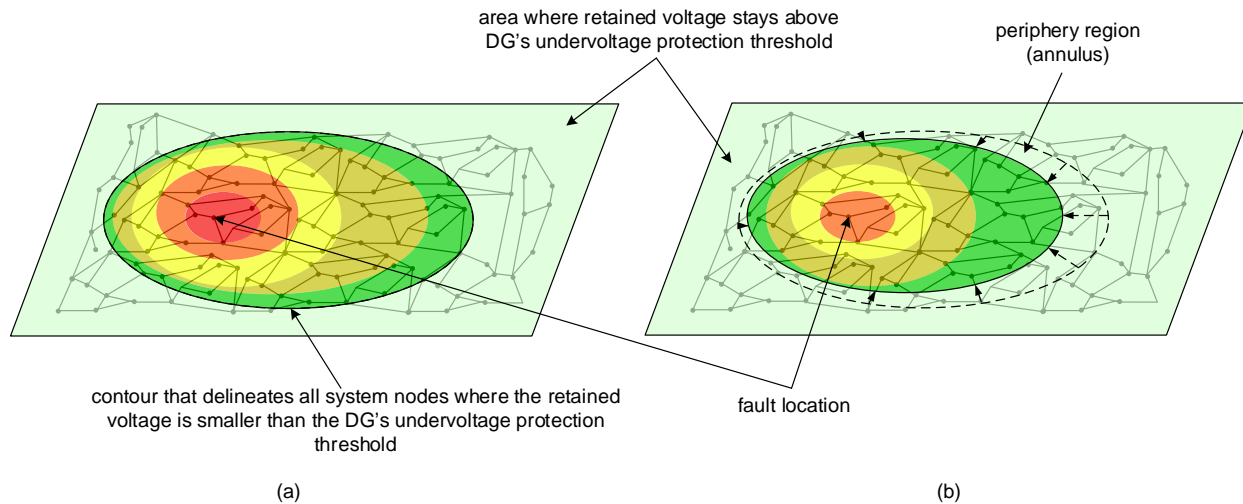


Figure 3: Illustration of the area where modeling accuracy of Distributed Energy Resources is critical. [2]

Additional model complexity that is unlikely to increase system-wide modeling accuracy should be avoided.

Until a few years ago, very little research has been published on dynamic equivalencing of stability models for active distribution systems (ADSs) that comprise significant amounts of DERs [30]. Publication [31] summarizes the state-of-the-art for the application of dynamic equivalencing methods to derive aggregated models of ADSs.

Recently, a consensus is evolving that *grey box modeling* is recommended for equivalent modeling of ADSs when sufficient physical knowledge is available. A grey box modeling approach is based on physical understanding of the structure and composition of the distribution system for which equivalent is being developed. System identification techniques are then used to identify model parameters based on measurements at the point of common coupling with the BPS (the boundary bus between the studied system and the system for which the equivalent is being developed). The computational challenges are reduced and these composite models can be easily integrated in dynamic simulation tools.

Notable former publications include NREL's *analytical method* of equivalencing the collector system of large wind power plants for steady-state studies [32], a generic dynamic model of an active distribution system for BPS stability studies [33; 34], and WECC's dynamic *reduced-order stability model* of DERs in distribution systems considering partial loss of DER in-feed described below [6; 35].

WECC's simplified distributed PV model (*PVD1* [6; 36]) is currently not widely applied and may require further refinement. However, WECC's proposed simplified equivalent model for distributed PV systems (*PVD1*) behind a single equivalent distribution feeder impedance (Figure 4) can currently be regarded as the "best-in-class" reduced-order modeling approach for *practical* power system studies. This model is described in WECC's "PV Power Plant Dynamic Modeling Guide" [6] and is similar to the model described in [35] for the first time.

WECC's Simplified Equivalent Model for Distributed PV (PVD1)

WECC's simplified equivalent model for distributed PV systems (*PVD1*) is a highly reduced, almost algebraic model to represent distributed PV systems in BPS stability studies. It includes active power control, reactive power control, and protective functions [36] and can account for partial tripping of distribution connected PV systems without the need to represent the distribution feeders explicitly; it can also consider the evolving mix of

distributed energy resources with and without ride-through capabilities, hence beyond default settings in IEEE Std. 1547-2003 [7]. The model structure of PVD1 is shown in Figure 4.

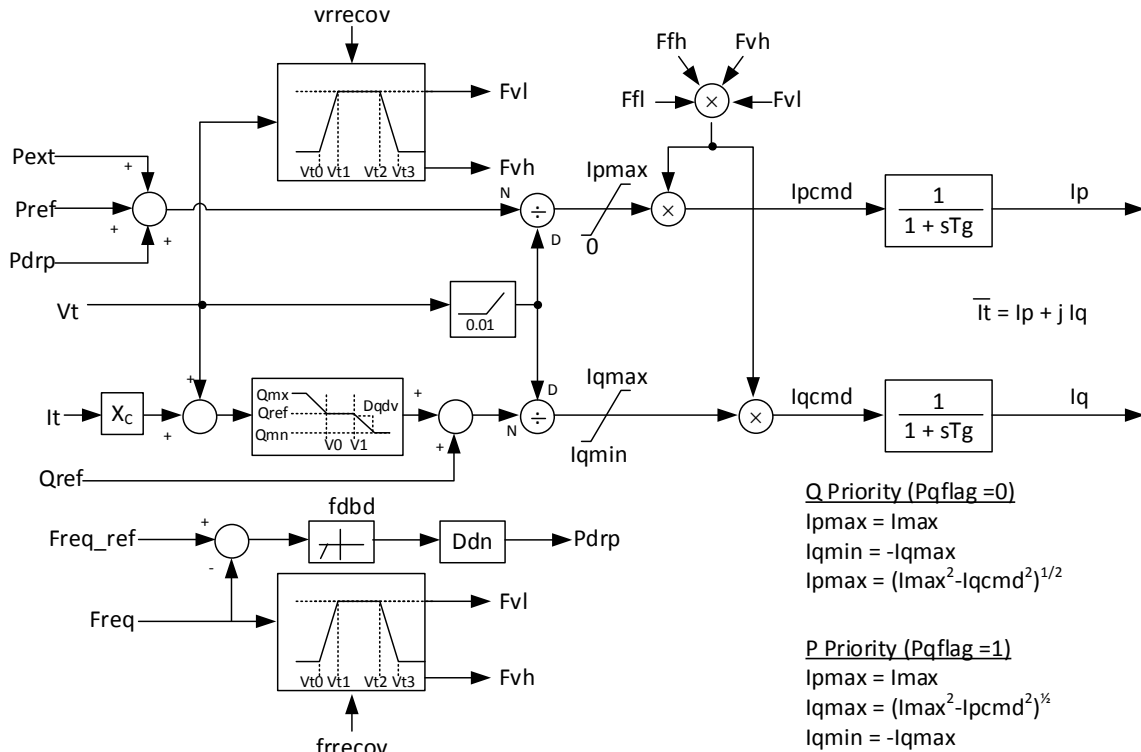


Figure 4: WECC Distributed PV Model Block Diagram. Source: EPRI figure based on [37].

An indicative verification and analysis of the accuracy of the *PVD1* model has been conducted by Electric Power Research Institute (EPRI) in [38], including a comparison of modeling results with a more detailed DER aggregation technique as proposed in [2]. It was shown that the *PVD1* model accurately represents the amount of tripped DER power in the post-fault period as long as ‘dynamic voltage support’ from new-to-be connected DERs is neglected. The *PVD1* model simplifies the DER dynamics that occur *during* the fault period significantly by assuming ‘momentary cessation’ (a pause at zero power, but remaining online) of DERs that ride through faults; this could potentially overestimate the amount of partial DER tripping. Neither does the *PVD1* model represent the delay of the protection functions. Overall, the *PVD1* model tends to produce conservative results because it tends to suggest a greater loss of DER generation than would likely be seen in the real system being simulated.

With the current limitations of WECC’s *PVD1* model to represent dynamics during the fault period, the *PVD1* model may not be suitable for this type of study. The use of detailed generic DER models used for utility-scale DERs (larger than 10 MVA) is recommended.

WECC’s Composite Load Model with Distributed PV (CMPLDWG)

Besides modeling of DERs, proper representation of load is important, especially in terms of voltage dependency [39]. Figure 5 illustrates WECC’s Composite Load Model [40] with distributed PV (CMPLDWG). The *PVD1* model is currently integrated into this model in a fixed way that limits the flexible use of the model. However, a modular approach will become available in the near future.

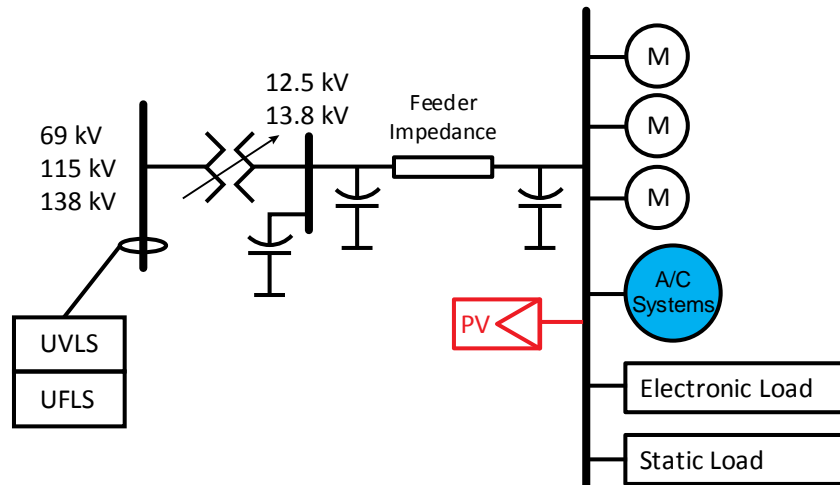


Figure 5: Distributed PV Model Block Diagram. Source: EPRI figure based on [40].

A study of the combined WECC Composite Load model (CMPLDWG) and PVD1 models was undertaken by NREL in [42] and included a comparison of the combined models results and detailed distribution-level analysis of various substation-level voltage sags in order to determine the amount of DERs that would trip offline if interconnected under the IEEE 1547-2003 standard. Tuning the CMPLDWG and PVD1 model parameters resulted in good agreement of the amounts of DERs that would trip offline for a given voltage sag magnitude. However, the tuned model parameters that gave good agreement did not match expected physical model parameters for the distribution circuit models and the functionality of the modeled PV systems (i.e. agreement between models and analysis was poor when the CMPLDWG and PVD1 models were populated with expected physical model parameters). This study indicated that either the voltage diversity of a distribution circuit cannot be sufficiently modeled using the CMPLDWG and PVD1 models or some modifications to the expected model inputs, currently based on physical/functional parameters, is required for tuning the combined models.

Chapter 4: Characteristics of Non-Synchronous DERs

Background

To determine how DERs may interact with the power grid, it is necessary to understand how these resources operate. DER operating characteristics are determined by the generating technology employed. Synchronous machines operate as conventional generators from a performance perspective, and these characteristics are well understood by the industry. Non-synchronous generation technologies, such as solar photovoltaic or fuel cell resources, rely on their direct current (DC) to alternating current (AC) inverter technology to delivery energy to an AC system. DC to AC inverter electrical performance requirements are designed to protect the user (public) and the inverter equipment from electrical hazards as well as to offer capabilities necessary for the reliable operation of the power grid to which the non-synchronous generators are connected. The commonly adopted governing requirements today are Underwriters Laboratory (UL) 1741 (2010) and (IEEE)'s 1547-2003.

UL 1741 is a product safety standard and primarily covers the hazard component of the inverter function. UL standards generally address electrical, fire and mechanical hazards, in addition to verification of electrical ratings. Additionally, UL 1741 reflects the interconnection performance requirements of IEEE 1547.1.

IEEE 1547-2003 is a standard for interconnecting DERs with the power grid and the associated requirements apply to the point of common coupling (PCC) between the grid and the DERs. These requirements address technical specifications and performance requirements for the inverter including voltage and frequency ride-through, voltage regulation, response to abnormal conditions, reclosing coordination, power quality and islanding, among other issues. IEEE 1547-2003 specifically prohibits the DERs from regulating voltage at the PCC. In addition, compliant devices do not regulate frequency at the PCC, and they cannot energize the local grid when islanded.

An amendment to IEEE 1547-2003 was made denoted as IEEE 1547a [43]. This amendment specifically allowed voltage regulation at the PCC and widened voltage and frequency operation ranges to accommodate voltage and frequency ride-through requirements desired by some utilities. The ongoing full revision of IEEE 1547 will “set the stage” for DERs to provide additional reliability services. Equipment meeting these proposed specifications will have capabilities beyond isolation detection and will become active power controllers that can provide reliability services. These reliability services may include voltage support, voltage regulation, and frequency regulation.

In addition, the California Public Utilities Commission (CPUC) regulates the largest rollout of DERs in North America in the California ISO balancing area and sets the technical and commercial standards for DER interconnection and operation according to its Rule 21. The CPUC has implemented new technical standards for the DER systems that are intended to go beyond safety and hazard issues and “establish programmable functions” that DER systems will perform to support power system operations.

However, the majority of existing fleet of DERs conforms to IEEE 1547-2003. Therefore, the performance of the existing DER fleet is unlikely to change until normal equipment replacements occur. Nevertheless, the performance of the installed fleet could change rapidly with the rapid growth of new PV that complies with new interconnection standards.

Voltage Ride-Through (VRT) and Frequency Ride-Through (FRT) Characteristics and Consequences

The voltage and frequency performance of DERs is currently not coordinated with BPS requirements. DER resources are not explicitly modeled as generating resources in operating and planning analysis tools, either in real-time or offline studies. Therefore, an event that causes a large amount of DERs to isolate from the power grid could result in unpredicted BPS behavior. The most likely event is low voltages over a wide geographic and electrical area caused by a fault on the sub-transmission (<230kV) systems connected to load and DERs. Fault clearing times are often dictated by relay coordination issues, which can lead to longer fault clearing times, particularly at lower voltages.

However, faults on the sub-transmission system can result in low voltage at the DERs resulting in the isolation of that resource. Consequences of this isolation could be more severe fault induced voltage recovery (FIDVR) or a significant increase in perceptible BPS load until the DER resources reconnect to the power grid. To date, in most regions, these problems have not become very noticeable. However, system performance at 5% DER penetration will differ from that where DERs are at 25% penetration. Loss of a large amount of DERs during a fault could result in system performance similar to the loss of a BPS generator. If the potential separation of DERs approaches a Balancing Authority's Most Severe Single Contingency (MSSC), care must be taken to ensure that adequate contingency reserves are available for such an event.

Similar issues apply for frequency ride-through. In WECC, the largest credible generation contingency is the outage of two nuclear units at the Palo Verde plant. This results in a loss of 2,740 MW, with a resulting frequency decline of 0.29 Hz, or a 59.71 Hz nadir (BAL-003-1 interconnection frequency response obligation (IFRO) calculation for WECC). This is above the IEEE 1547 separation point of 59.3 Hz. However, the WECC Off-Nominal Frequency Plan begins tripping at 59.5 Hz, and continues tripping down to 58.3 Hz. If an under-frequency load shedding event occurred, DERs are likely to trip off-line at 59.3 Hz, dramatically increasing perceptible load on the BPS, and further depressing frequency. It is important to recall that IEEE 1547 specifies minimum performance requirements. DER equipment manufactures may exceed 1547 trip requirements resulting in DER tripping before 59.3 Hz is reached. This implies that significant DER separation could occur at frequencies higher than 59.3 Hz, but all separation would occur by 59.3 Hz.

With respect to the BPS, voltage and frequency ride-through are key to system performance. Today, DER resources are typically netted with distribution load when measured and modeled. Consequently, the operator of the power grid is not aware of the total load and total interconnected DERs. If a system event occurs, be it a voltage or frequency excursion, and that excursion exceeds the inverter isolation settings, it is likely that a significant amount of DERs may automatically disconnect. This can instantaneously and significantly increase net load during such an event, thereby exacerbating the underlying disturbance that caused the voltage or frequency excursion. The impact of the change in net load is proportional to the amount of DERs that isolates from the power grid. As DER penetration increases, the effects of this sudden load surge on the BPS increase.

The existing IEEE 1547-2003 performance requirements for voltage and frequency ride-through are documented below. These requirements have been overlaid with NERC's frequency and voltage requirements (PRC-024 Attachment 1 and 2, respectively) and illustrate areas of concern where large penetrations of DERs could adversely impact reliability. DERs must isolate when these conditions are met as shown in Table 1 and Figure 6 for voltage and in Table 2 and Figure 7 for frequency.

Table 1: Voltage Ride-Through Conditions (DERs must isolate when these conditions are met)		
DER Size	Voltage (pu)	Isolation Times (seconds)
≤ 30 kW	< 0.50	0.16
	0.50 < 0.88	2.0
	0.88 < 1.10	Run Continuously
	1.10 < 1.20	1.0
	≥ 1.20	0.16
> 30 kW	Tripping points are field adjustable	

PRC-024— Attachment 2

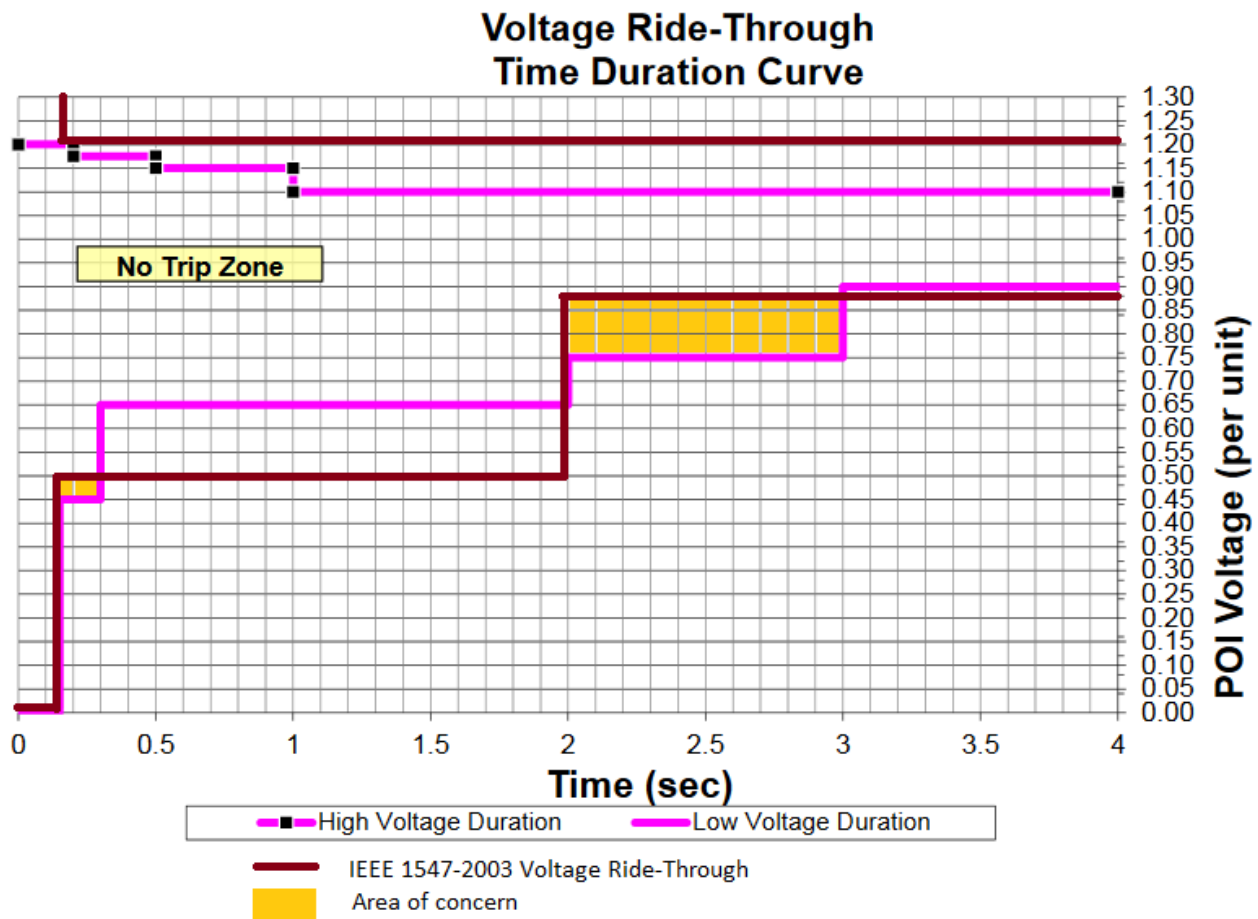


Figure 6: NERC PRC-024-2 and IEEE 1547-2003 voltage ride-through.

Table 2: Frequency Ride-Through Conditions (DERs must isolate when these conditions are met)		
DER Size	Frequency Range (Hz)	Clearing Times (sec)
≤ 30 kW	> 60.5	0.16
	< 59.3	0.16
	> 60.5	0.16
> 30 kW	< 59.8 – 57.0 adjustable	0.16 – 300 adjustable
	< 57.0	0.16

PRC-024 — Attachment 1

OFF NOMINAL FREQUENCY CAPABILITY CURVE

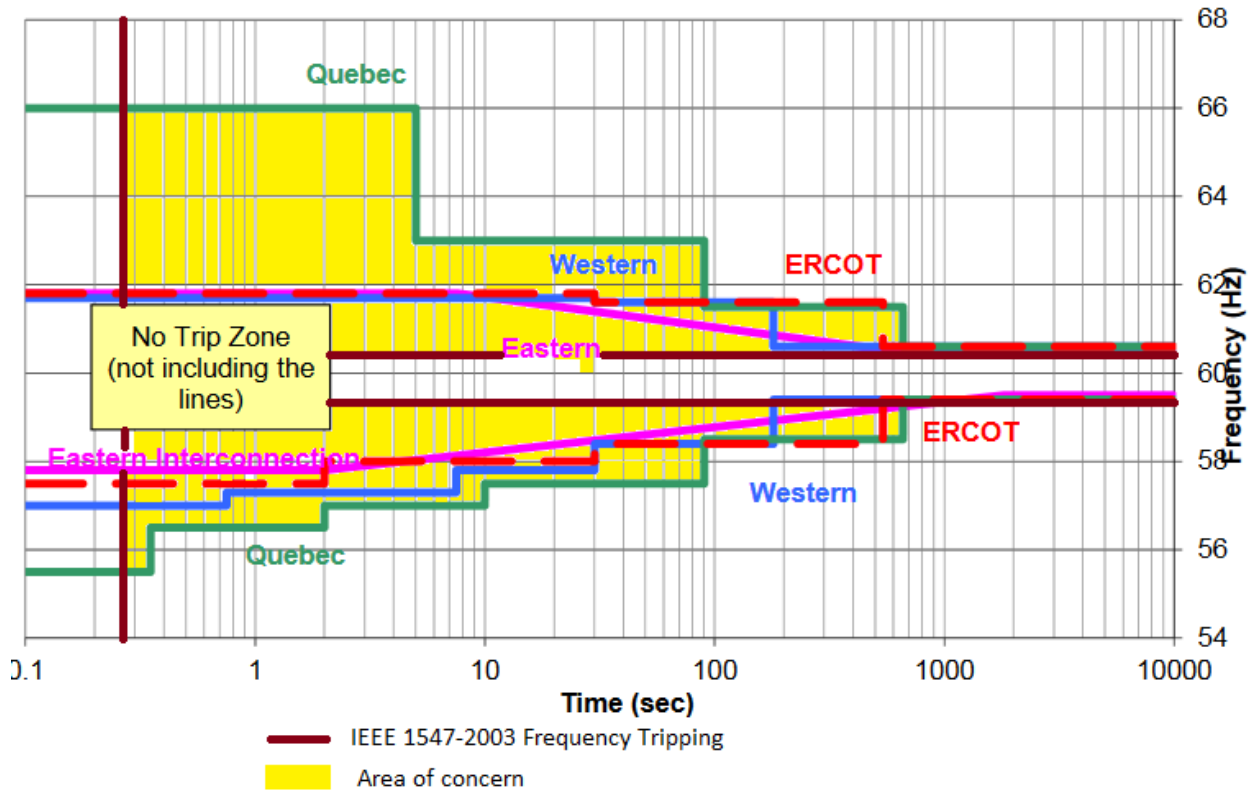


Figure 7: NERC PRC-024-1 and IEEE 1547-2003 and frequency ride-through.

PRC-024-2 frequency ride-through requirements are designed such that under frequency load shedding (UFLS) schemes will operate before generators begin to disconnect from the BPS. Smaller DER installations, under 30 kW, can begin disconnecting from the BPS without respect to coordination with the area UFLS. When DERs disconnect, BPS net load will increase, and this will further depress frequency, potentially leading to premature system instability.

IEEE 1547-2003 currently prohibits energizing the DERs if the area is de-energized/islanded, which precludes independent operation of DERs. This is done largely for safety considerations, so that islanding does not result in

energized lines. In broad terms, DERs can be considered “passive” resources in the sense that they do not directly regulate voltage or frequency. From the point of energy balance, DERs operate as a “negative load.”

IEEE 1547 is currently being updated. This effort will include frequency and voltage ride-through capability that can better support BPS reliability. It is also likely that the update will include voltage and frequency regulation capabilities and communications capability is also being discussed. These efforts are ongoing, but will not affect DERs that is installed before the revisions become effective. The DERTF supports the concepts being proposed to IEEE 1547 and capabilities to allow for situational awareness.

California Rules for DERs

The California Public Utilities Commission (CPUC) regulates the largest rollout of DERs in North America in the California ISO balancing area and sets the technical and commercial standards for DER interconnection and operation according to its Rule 21. Rule 21 primarily follows the IEEE 1547 parallel operation DER interconnection standard where generation is operating in parallel (synchronously connected) with the system rather than in an islanded or isolated mode. CPUC is in the process of implementing new technical standards for the DER systems that are intended to go beyond safety and hazard issues and “establish programmable functions” that DER systems will perform to support power system operations. A report prepared by the CPUC Smart Inverter Working Group notes:¹

“[An] increasing number of DER systems can impact the stability, reliability, and efficiency of power grid operations. First, DER systems are usually located for the convenience of the DER owner, not the utility, and therefore may be in less-than-optimal locations from the perspective of grid operators. Second, DER systems are of widely varying sizes and purposes (e.g., as secondary to offsetting customers’ loads and/or their power production). Third, without coordination with the distribution equipment on the grid, DER systems could actually cause voltage oscillations, create reverse power flows on circuits not designed for two-way flows, and cause other power system impacts that could actually increase the frequency and durations of outages.”

The CPUC report not only covers the new standards for DER systems but also notes how utilities will be able to monitor and control these systems and their functions. Most notably:

“DER systems can respond to commands to override or modify their autonomous actions by utilities and/or retail energy providers. In some cases, DER systems, just like bulk power generation, may be directly monitored and controlled by utilities in real-time. In other cases, these ICT [Information and Communications Technology] capabilities may issue emergency commands, or may support normally autonomous operations by updating software settings, providing demand response pricing signals, establishing schedules for energy and ancillary services, adjusting the curves for active and reactive power, and other types of utility-DER interactions.”

Per CPUC plans, the following autonomous inverter functionalities will be added to the technical operating standards in Rule 21 by the end of 2017:

1. Support anti-islanding to trip off under extended anomalous conditions;
2. Provide ride-through of low/high voltage excursions beyond normal limits;

¹ CPUC Smart Inverter Working Group, “Recommendations for Updating the Technical Requirements for Inverters in Distributed Energy Resources,” January 2014

http://www.energy.ca.gov/electricity_analysis/rule21/documents/recommendations_and_test_plan_documents/Recommendations_for_updating_Technical_Requirements_for_Inverters_in_DER_2014-02-07-CPUC.pdf.

3. Provide ride-through of low/high frequency excursions beyond normal limits;
4. Provide volt/VAR control through dynamic reactive power injection through autonomous responses to local voltage measurements;
5. Define default and emergency ramp rates as well as high and low limits;
6. Provide reactive power by a fixed power factor; and
7. Reconnect by “soft-start” methods.

The implementation road map, as recommended by the CPUC Smart Inverter Working Group, consists of the following steps:

1. A nationally recognized testing laboratory or laboratories have made an accepted revised ANSI/UL 1741 testing procedure available to test the added autonomous inverter functionalities noted above;
2. Immediate modification of Rule 21 to allow the installation of certified inverters that include the proposed autonomous inverter functionalities applying for interconnection under Rule 21;
3. Consideration of an 18-month transitional permissive period during which the investor-owned utility distribution provider and the DER system installer may, by mutual agreement during the interconnection process, activate one or more of the autonomous functionalities for the purposes of conducting pilot operations, analysis, and publishing the results of any analysis;
4. Following the transitional permissive period and based on operational data collected and published during that period as well as any other relevant factors, CPUC would mandate the autonomous smart inverter functionalities for inverter-based distributed energy systems applying for interconnection under Rule 21; and
5. Upon further recommendations and future proposals by the CPUC Smart Inverter Working Group, CPUC would consider communications capabilities and advanced inverter functionalities for inverter-based distributed energy systems in California.

In addition to the autonomous inverter functionalities noted above, CPUC is evaluating the implementation of the following advanced communication functionalities for inverter based DER systems:

1. Provide capability for including and/or adding communications modules for different media interfaces;
2. Provide the TCP/IP internet protocols;
3. Use the international standard IEC 61850 as the information model for defining data exchanges;
4. Support the mapping of the IEC 61850 information model to one or more communications protocols;
5. Provide cybersecurity at the transport and application layers; and
6. Provide cybersecurity for user and device authentication.

Finally and beyond the autonomous inverter and communication functionalities noted above, CPUC will consider the following advanced functionalities for the DER systems in the future:

7. Provide emergency alarms and information;
8. Provide status and measurements on current energy and ancillary services;
9. Limit maximum real power output at the Point of Common Coupling (PCC) upon a direct command from the utility;
10. Support direct command to disconnect or reconnect;

11. Provide operational characteristics at initial interconnection and upon changes;
12. Test DER systems software patching and updates;
13. Counteract frequency excursions beyond normal limits by decreasing or increasing real power;
14. Counteract voltage excursions beyond normal limits by providing dynamic current support;
15. Limit maximum real power output at the Electrical Connection Point (ECP) or optionally at the PCC to a preset value;
16. Modify real power output autonomously in response to local voltage variations;
17. Set actual real power output at the point of common coupling (PCC);
18. Schedule actual or maximum real power output at specific times;
19. Smooth minor frequency deviations by rapidly modifying real power output to these deviations;
20. Follow schedules for energy and ancillary service outputs; and
21. Set or schedule the storage of energy for later delivery, indicating time to start charging, charging rate and/or “charge-by” time.

Chapter 5: Previous Work of the NERC IVGTF Task Force

NERC has taken a detailed look at the potential impacts of DERs on the BPS in the form of solar photovoltaic systems (PVs) on the distribution system. This work was documented in the NERC Integrating Variable Generation Task Force Task 1-7 report entitled “[Performance of Distributed Energy Resources During and After System Disturbance: Voltage and Frequency Ride-Through Requirements](#)” that was issued in December 2013.

This earlier task force stated that a large amount of distribution-connected generation may have significant effect on the reliability of the BPS. Of particular concern was the lack of disturbance tolerance, which entails voltage ride through (VRT) and frequency ride through (FRT) capability. Other than CPUC Rule 21, which was recently implemented, there are currently no North American VRT or FRT DER requirements in place today.

The IVGTF made the following general recommendations in its report:

- 1. In the short-term, NERC should engage in current efforts to revise DER interconnection standards by providing information, raising awareness and encouraging the adoption of VRT and FRT for DERs. The initial focus should be on identifying the need for adopting minimum tolerance thresholds for VRT and FRT in the IEEE Standard 1547 and, then, establishing those minimums.*
- 2. In the longer-term, NERC should establish a coordination mechanism with IEEE Standard 1547 to ensure that BPS reliability needs are factored into future DER interconnection standards revision efforts. To date, BPS stakeholders have participated only sporadically in the IEEE Standard 1547 process. As a result, VRT and FRT concepts receive limited consideration and may have been outweighed by distribution system protection concerns. This liaison process would be too late for the P1547a amendment, but it would be timely for the full revision to begin in December 2013.*

The IVGTF offered the following general guidelines on voltage ride-through (VRT) and frequency ride-through (FRT) specifications for distributed VEs and other DERs, for consideration in the IEEE Standard 1547 revision. It is assumed that VRT and FRT requirements would have to co-exist with revised “must trip” provisions needed to address safety and protection/coordination issues in distribution systems.

1. The revised IEEE Standard 1547 should allow for different methods of meeting the functional requirements of fault detection (clause 4.2.1), reclosing coordination (clause 4.2.2), and unintended islanding detection (clause 4.4.1). At present, DERs meeting those functional requirements would still have to trip on voltage (clause 4.2.3) and frequency (clause 4.2.4) excursions. Removing those linkages would help pave the way for VRT and FRT requirements. The IVGTF recognizes that these alternative methods are more expensive, require more engineering effort, and in some cases require further technical development. However, the increasing level of DERs and the potential impact on the BPS justifies the effort.
2. The revised IEEE Standard 1547 should include explicit low and high VRT requirements. Likewise, the revised IEEE Standard 1547 should include explicit low and high FRT requirements. These requirements should be expressed as voltage versus cumulative time and frequency versus cumulative time requirements.
3. Must-trip voltage thresholds in the existing IEEE Standard 1547 should be extended to accommodate an effective VRT envelope without overlap (Figure 8).
 - a. As an example, Figure 8 shows a possible approach for low voltage ride-through down to 50 percent voltage for 10 cycles (160 milliseconds), within the existing IEEE Standard 1547 framework.
 - b. Zero voltage ride-through is not required for BPS reliability. A ride-through level down to approximately 50 percent voltage would provide adequate tolerance during transmission faults.

- c. A ride through period longer than shown in Figure 8--possibly greater than 10 seconds--at higher voltage level (e.g., down to 70% voltage) may be needed to avoid compounding fault-induced delayed voltage recovery (FIDVR).

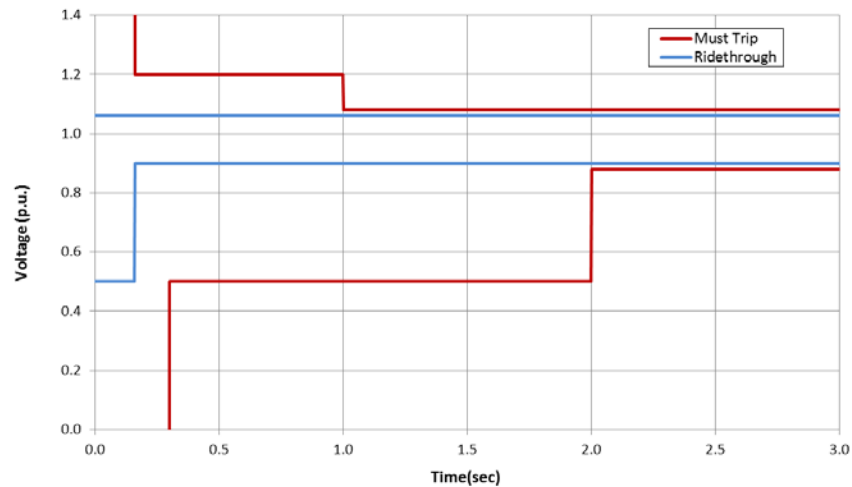


Figure 8: IVGTF 1-7 Recommended Ride-Through and Must-Trip Requirements for DER.

- Must-trip frequency thresholds in the existing IEEE Standard 1547 should be extended to accommodate an effective FRT envelope without overlap.
- The time dimension of the VRT/FRT curves discussed previously is meant to represent cumulative time elapsed since the onset of a disturbance event that result in temporary excursions of voltage and/or frequency. The VRT/FRT envelopes should not establish must-run ranges for generators (i.e., they should not prevent intentional shutdown of a DERs for reasons other than grid voltage and frequency disturbances, such as normal shutdown of PV at night or by operator action.)
- The prospective disturbance tolerance standard should provide a default VRT and FRT envelope, but should allow for the time and frequency/voltage magnitudes to be adjustable, within certain limits, for coordination with local protection, in coordination with the distribution system operator.
- FRT and VRT requirements should cover all DERs that are normally grid connected, regardless of size or technology. However, a range of thresholds could be considered based on technology differences (e.g., inverter versus rotating machines), as some European grid codes do. In general, focusing requirements on the truly functional needs of the grid tends to eliminate the need to have technology-specific requirements.
- The restarting of DERs during system restoration should be considered during the development of DER interconnection requirements. While the restoration situation in North America is somewhat mitigated at present by the sequential nature in which distribution feeders will likely be reenergized after a major blackout, reliability impacts of DERs should consider the automatic restarting of DERs. Failure to consider and mitigate these impacts could lead to further instability during a disturbance.

Since this IVGTF report was posted in December 2014, efforts have commenced to harmonize the PRC-024-2 VRT and FRT requirements with IEEE 1547. Several ERSWG and DERTF members have been participating in IEEE 1547 Subgroup III Section 4.2 (voltage and frequency ride-through). As of this writing, it appears that the 1547 update will respect PRC-024-2 voltage and frequency ride-through requirements. As always, it will be incumbent on the local distribution owner/operator to ensure that these requirements are understood and implemented properly.

Chapter 6: NERC Reliability Standards

Background

NERC Reliability Standards exist to address the reliability needs of the interconnected electricity systems. These standards apply to the bulk electrical system (BES) as specified by the BES definition adopted by FERC in March 2014. In some cases, standards apply to devices and needs beyond the BES. Historically, standards have not been written to apply to equipment within the distribution utility unless it has a direct impact on the effect of grid reliability, such as load shedding or system restoration. Each standard identifies the applicable registered entities, and Distribution Providers are identified as applicable entities for some of the standards.

NERC generation standards, generally, do not address resources connected to the grid at voltages below 100kV, nor do they address resources with less than a registered capacity of 75MVA in aggregate or 20MVA for an individual unit. The standards do not explicitly address energy resources (e.g., solar, wind or hydro facilities) that are contained within the distribution system footprint. However, some standards provide for the collection of pertinent information for planning and system operations purposes.

The impact of DERs on the bulk power system (BPS) is not a simple issue. Over the last several decades, the electric industry has operated with the majority of its generation integrated at the transmission system level. More recently, there has been a greater integration of generation resources within the distribution system under the support of renewable portfolios and societal expectations for a modernization of the grid. These changes have altered the power flows at the transmission–distribution (T-D) interface. Whereas in the past, distribution entities have drawn their generation needs from the BPS, some distribution entities are increasingly a source of resources that will support some local needs or even flow power back to the BPS. At lower penetration levels, the overall impact of DERs is minor and insignificant to the BPS. That is, as the output of these resources varies throughout the day or if these resources were to trip offline during large system disturbances, the changes imposed to BPS voltage and frequency are minor and are managed by existing BPS resources. However, as the penetration of DERs increases, their impact on the BPS becomes more substantial. At higher penetration levels, issues may develop in transmission line loading, grid voltage and system frequency during normal or disturbed operation. These actions will have similar impacts to those that NERC described in the Essential Reliability Services report published in December 2015.

Accurate models for the operation and planning processes are vital. It is necessary for system planners and operators to have access to information regarding the capacity and behavior of DERs at the T-D interface. Refined information and models allow planners and operators to make more informed decisions regarding resource adequacy, system improvements, recovery and demand balancing for the BPS. The addition of DERs may initially appear to simply reduce the demand and the loading levels at the T-D interface, but the reality is actually more complex. Both planning and operating assessments need to accurately represent how DERs interacts with the complex load characteristics of the distribution system. The inclusion of DERs in models and assessments yields valuable insight into how the BPS will perform and how distribution level resources can impact operating limits and margins in the interconnected system.

Review of Existing NERC Standards

The DER task force reviewed the current set of NERC standards and determined there is no need for additional standards to be developed to address an increasing penetration of DERs. However, the DERTF recommends that DP be added as an applicable entity in MOD-032, replacing the Load Serving Entity, which is a current applicable functional entity. MOD-032 provides Planning Coordinators and Transmission Planners with the mechanism to collect data necessary for steady state, dynamics, and short circuit modeling from applicable entities.

While there are no explicit NERC requirements to independently model and assess DERs for purposes of BES system planning or operations, the transmission operators and transmission planners have requirements to accurately model and address reliability risks. This includes the impact of DERs, where material. Current standards (TOP-003-3, IRO-010-2, & MOD-032-1) provide broad authority for system operators and transmission planners to obtain the information needed for models and reliability assessments. This provides the ability to collect pertinent information as related to distribution impacts on the BES. As described in Chapter 3, the necessary DER information can generally be in somewhat aggregated form, but with enough detail to allow accurate modeling of the characteristics and behaviors at the transmission-distribution (T-D) interface. This level of detail also extends to forecasting and operating issues.

With this in mind, additional analysis is needed to ascertain how an increasing penetration of resources within the distribution system footprint will influence the change of power flows at the T-D interface. The DERTF recommends that a set of guidelines be developed to assist in modeling and assessments, such that owners/operators of the BPS can account for the impact of DERs at the T-D interface.

Chapter 7: Recommendations

The recommendations of the DERTF are listed below. The DERTF believes that it has completed the scope for the task force, and additional efforts should be part of ongoing ERSWG efforts.

- 1) **Guidelines:** The DERTF recommends that a set of guidelines be developed to assist in modeling and assessments, such that owners/operators of the BPS can account for the impact of DERs. The DERTF also recommends that Distribution Provider (DP) be added as an applicable entity in MOD-032, replacing the Load Serving Entity that is currently an applicable entity, to provide for collecting pertinent information related to distribution impacts on the BPS (similar to what is already included in TOP-003-3).
- 2) **Data Sharing:** Data requirements and sharing of information across the transmission-distribution (T-D) interface should be further evaluated to allow for adequate assessment of future DER deployments. The important near-term issue is sharing of information to facilitate accurate modeling for transmission planning and operations. At some point, additional consideration may be needed for stability, protection, forecasting, reactive needs, and real time estimates for operating needs.
- 3) **Modeling:** Based on reliability considerations for modeling purposes, generation from DERs should not be netted with load as penetration increases. Load and DERs should be explicitly modeled in (a) steady-state power flow and short-circuit studies and (b) dynamic disturbance ride-through studies and transient stability studies for BPS planning with a level of detail that is appropriate to represent the aggregate impact of DERs on the modeling results over a 5-10 year planning horizon. A modular approach to represent DERs in BPS studies, with some level of data validation, is recommended to ensure accurate representation of the resources for the specific BPS study type.
- 4) **Dynamic Models:** Dynamic models for different DER technologies are available and can presently be used to model the evolving interconnection requirements and related performance requirements. WECC's simplified distributed PV model (*PVD1*) provides a reasonable balance between modeling accuracy, computational requirements, and handling of the system model, but some further improvement may be needed.
- 5) **Coordination:** A coordinated effort by distribution and transmission entities is needed to determine appropriate use of future DER capabilities (such as settings available under proposed IEEE 1547 revisions). This must be coordinated with voltage and frequency ride through performance, and potentially coordinated with under frequency load shedding programs and BPS performance under PRC-024. Note that PRC-024 was developed with BES issues in mind, and where PRC-024-2 and desired distribution-level protection and operations conflict, the transmission and distribution utilities will need to coordinate the required DER ride-through settings to meet BPS reliability needs while minimizing distribution impact.
- 6) **Definitions:** Further examination is needed to determine whether DSM should be included in the DER definition and if the DER definition should be added to the NERC glossary and/or NERC functional model.
- 7) **Industry Collaboration:** Finally, the limited existing knowledge and experience of modeling DERs in system planning studies and operating with higher levels of DERs will require future collaborative research, knowledge exchange and learning. The industry should collaborate with vendors of power system simulation software and DER product vendors to continuously enhance models for DER representation in BPS planning studies. NERC can assist with coordination across the industry to facilitate the reliable integration of DERs into the BPS.

Appendix A: Typical Connection of Distributed Energy Resources

While defining DERs is an important first step, to fully understand the potential interaction of these resources with the BPS, it is essential to understand how these resources are interconnected to the power grid.

DERs, as defined within this document, are generally interconnected to a Distribution Provider's electric system at the primary voltage (≤ 100 kV but > 1 kV) and/or secondary voltage (≤ 1 kV). Interconnection design and installation typically meet requirements of the National Electric Code, the National Electrical Safety Code or any other locally designated code pertaining to electrical facility design, construction, or safety. Sample interconnection one-line diagrams of different types of DERs that are currently operating in parallel with a Distribution Provider's electric system are shown in the following figures. Shown in each figure are a point of change of equipment ownership, bi-directional meter and a visible air-gap switch.

The point of change of equipment ownership ("POCEO") defines the point where equipment owned and operated by the DER owner connects to equipment owned and operated by the Distribution Provider. Design and installation of equipment on either side of the POCEO is the responsibility of the owner of the equipment.

The bi-directional meter has two registers. One register captures energy flow from the Distribution Provider's electric system to the DER facility (i.e., delivered energy). The other register measures energy flow from the DER facility to the utility (received energy). Depending on the power purchase agreement ("PPA") executed between the DER Owner and the Distribution Provider determines the type of meter installed. In some cases, the Distribution Provider may install an advanced meter with capability of capturing 30-minute interval real power (kW), reactive power (kVA) and real energy (kWh) and readings are transmitted to the Distribution Provider. In other cases, a simple energy meter is installed.

A visible air-gap switch is sometimes required for isolating the DER facility from the Distribution Provider's electric system when work on a line section or equipment is performed, particularly for large DERs. The switch is generally required for the purpose of providing a visibly verifiable break (or air gap) between the facility and the Distribution Provider's electric system. Smaller DER systems may or may not be required to have a visible air-gap switch. All DERs fed from DC sources require a lockable DC disconnect switch.

The bi-directional-meter and visible air-gap switch are minimum interconnection requirements for some Distribution Providers. Other requirements include intertie protection that is designed to quickly isolate the DER facility for faults within the Distribution Provider electric system. The intertie protection may include a communication link between the DER facility and the Distribution Provider's electric system to prevent unintentional islanding.

A separate intertie protection is generally not required for inverter-based DER facilities that are Underwriters Laboratory (UL) listed, meet the utility compatibility requirements of UL Standard 1741 and the protection requirements of Institute of Electrical and Electronic Engineers (IEEE) Standard 1547-2003, and are determined to be capable of detecting faults on the utility side of the DER facility. However, the Distribution Provider generally performs commissioning testing of the DER facility to ensure that the IEEE 1547 protection is properly set and configured for parallel operation with the Distribution Provider's electric system. IEEE 1547 is currently under revision and is discussed in Chapter 3.

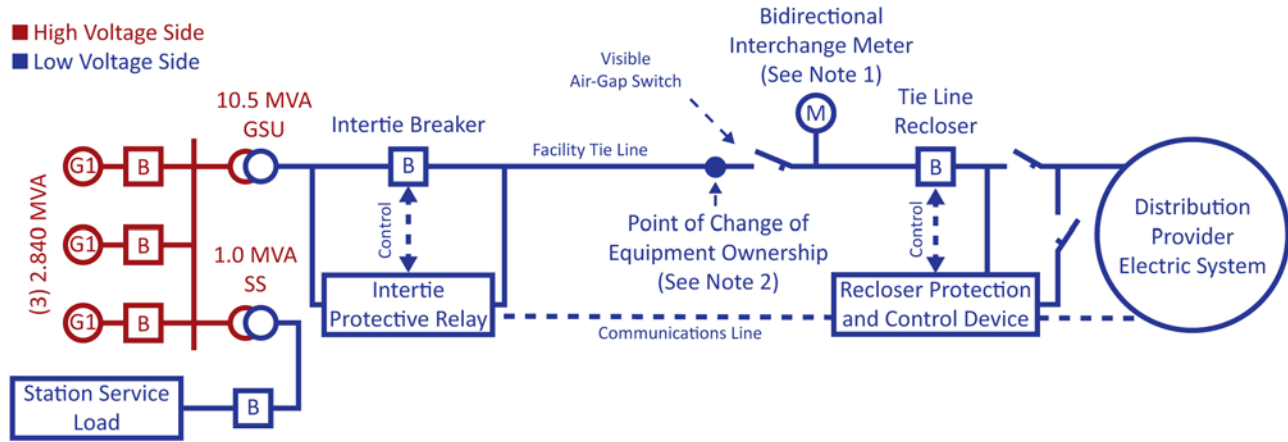


Figure 9: Interconnection of a large Landfill Gas Generation facility.

System impact studies performed by the Distribution Provider identified the need for a communications line for direct transfer trip of the DER facility. A tie line recloser is required to maintain reliability of service to existing end-use customers served by the Distribution Provider.

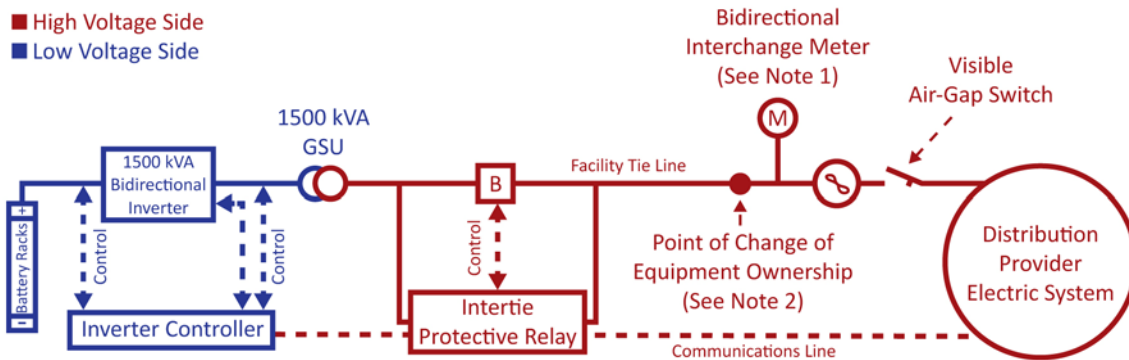


Figure 10: Interconnection of a large battery energy storage facility.

The inverter is not UL listed. Therefore, a separate intertie breaker with relays is required. System impact studies performed by the Distribution Provider identified the need for a communications line for direct transfer trip of the DER facility.

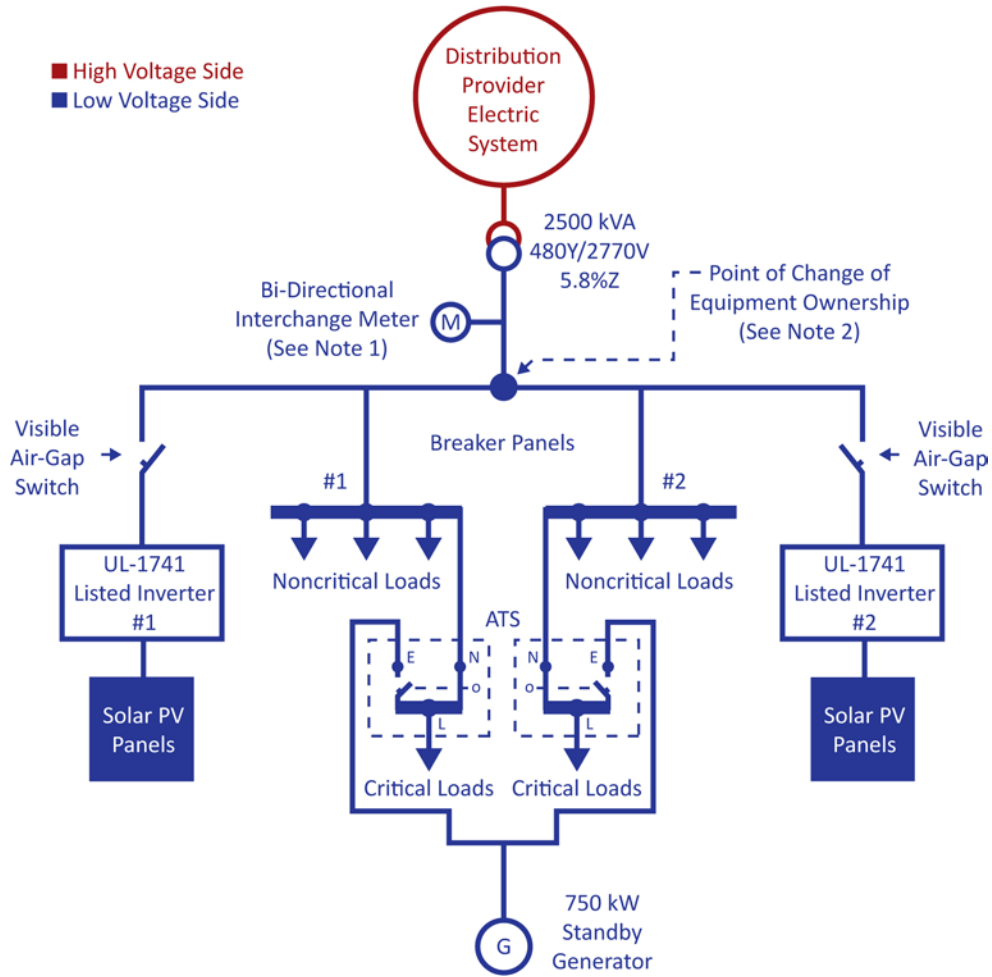


Figure 11: Interconnection of a behind-the-meter solar PV facility at a large commercial customer site with an existing standby generator.

Two UL-1741 listed inverter-based solar PV systems were installed primarily to offset electricity purchased from the distribution utility. In addition to this DER, customer also has a standby generator that can be used to serve critical loads within the facility.

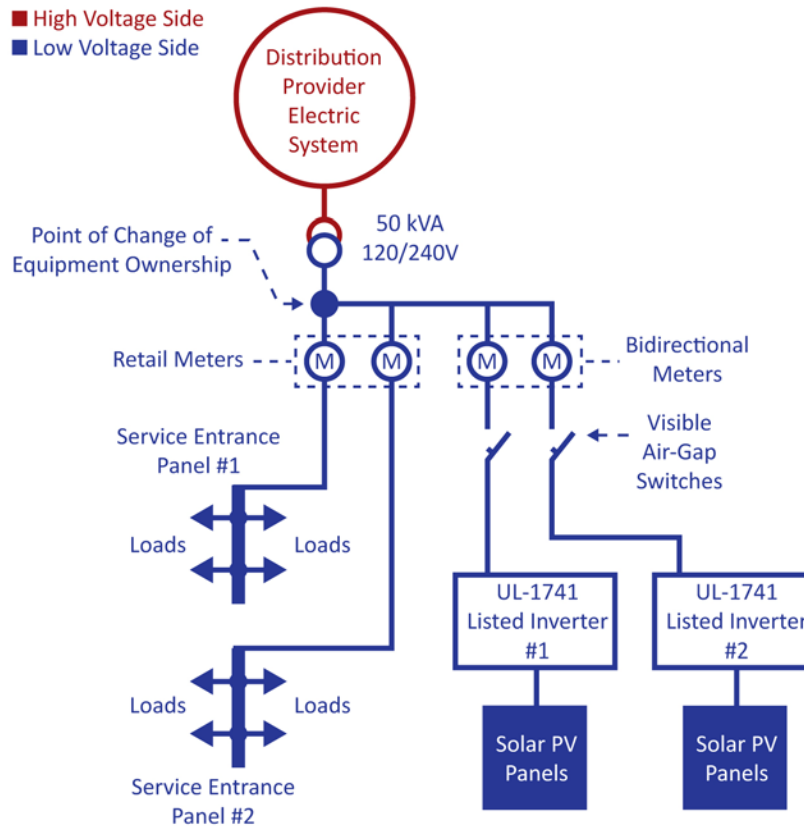


Figure 12: Interconnection of a solar PV merchant facility at a residential customer site.

DER facility output is sold to the Distribution Provider through the bi-directional meter. Distribution Provider provides electric service to the customer’s residence through two retail revenue meters and two service entrance breaker panel boards.

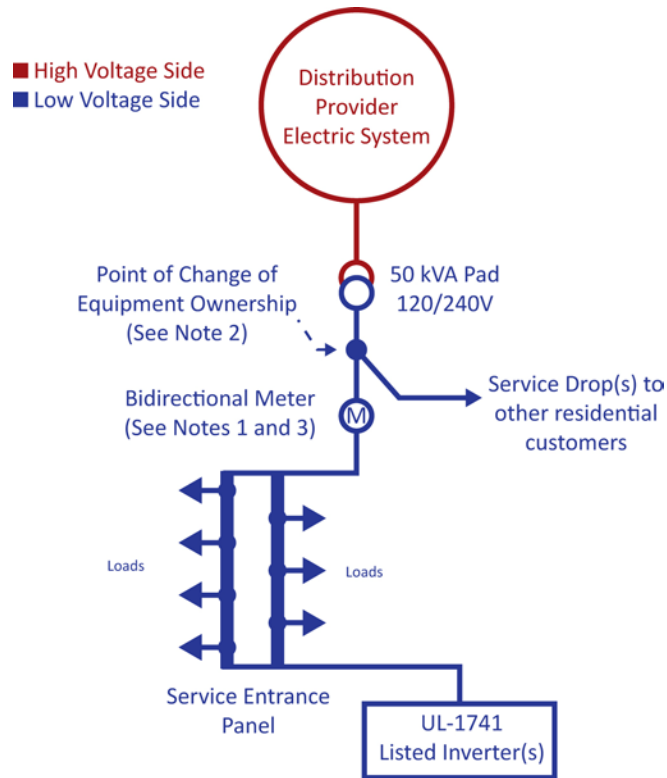


Figure 13: Interconnection of a behind-the-meter solar PV merchant facility at a residential customer site.

A single UL-1741 listed inverter-based system was installed to affect electricity purchased from the distribution utility. Net output from the facility is sold to the Distribution Provider through a bidirectional meter.

Appendix B: Operations and Long-Term Planning

As discussed throughout this report, the growth in quantity and diversity of DERs require enhanced short-term forecasting for operational purposes, operational coordination between the BPS operator and the distribution utilities, and long-term forecasting for planning. It is also important to have situational awareness of DER contributions and impacts in the operating timeframe, as well as considering the ability of DERs to participate as a dispatchable resource and contribute essential reliability services to the power grid in various ways.

This appendix provides an example of how these requirements are being viewed and addressed in California along with some general discussion. Given the many options and developing approaches to these topics, the DERTF offers some initial information in this appendix, but recommends that these topics receive additional consideration in future NERC task force, working group or subcommittee activities.

DER Impact on California ISO Operations

Currently the greatest operational impact of DERs in California comes from behind-the-meter solar photovoltaic (PV) installations. Figure 14 is the latest forecast of PV growth in the CAISO balancing authority area (BAA).

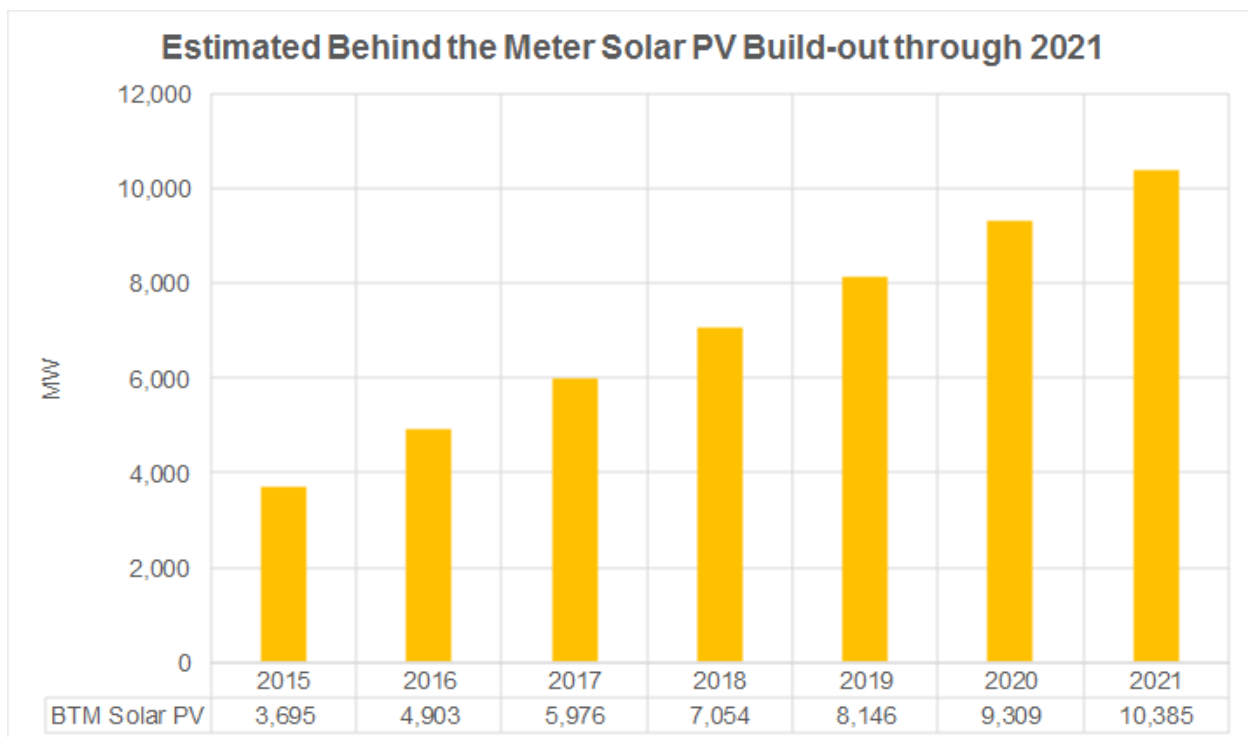


Figure 14: CAISO Behind the Meter (BTM) PV DER forecast.

CAISO's forecasted peak load in 2015 was 44,500 MW. In 2016, DER PV was over 10% of CAISO's peak load. At lower loads, DER PV is a higher proportion of load. As shown previously, voltage and frequency ride-through will not conform to BES requirements of PRC-024-2. BA load (such as for CAISO) is a calculated value consisting of net interchange and metered generation values.

$$\text{BA Load} = \text{Generation} + \text{Net Actual Interchange}$$

Behind the meter DERs are not typically metered. In general its affect is to reduce the amount of generation or net imports needed for system balance, i.e., the right-hand side of the above equation. Thus, DERs directly lowers

the measured load in a BA. In Figure 14, the “BTM Solar PV” value represents an equivalent amount of load that is not measured at the BA level.

In operations (resource commitment and dispatch) and planning (future needs) work, DERs represent another variable to consider. A distribution circuit with a 10 MW load may see increasing DER penetration over time. Assuming the actual physical load remains 10 MW, DERs will offset that value. Assuming a 50% penetration of PV, the distribution circuit load may see 5 MW of load at the circuit breaker, but the 10 MW of load is still there. As the solar angle decreases through the afternoon and evening, DER output will steadily decline while load remains high. This leads to lower than expected loads during the day, but circuit load increasing much faster through the late afternoon and evening hours. Ultimately, the circuit peak load can be 10 MW, but it occurs in the evening rather than in late afternoon. Circuit load during the morning and early afternoon will be lower than previously experienced. Therefore there is low resource commitment during the early part of the day, but very fast resource commitment and ramping requirements in late afternoon and evening, followed again by a very fast decommitment from evening to light load night hours, which can challenge the operational capability of the system. Figure 15 shows that actual net load is lower than originally estimated due to increased amount of renewable resources (including DERs) on the CAISO system.

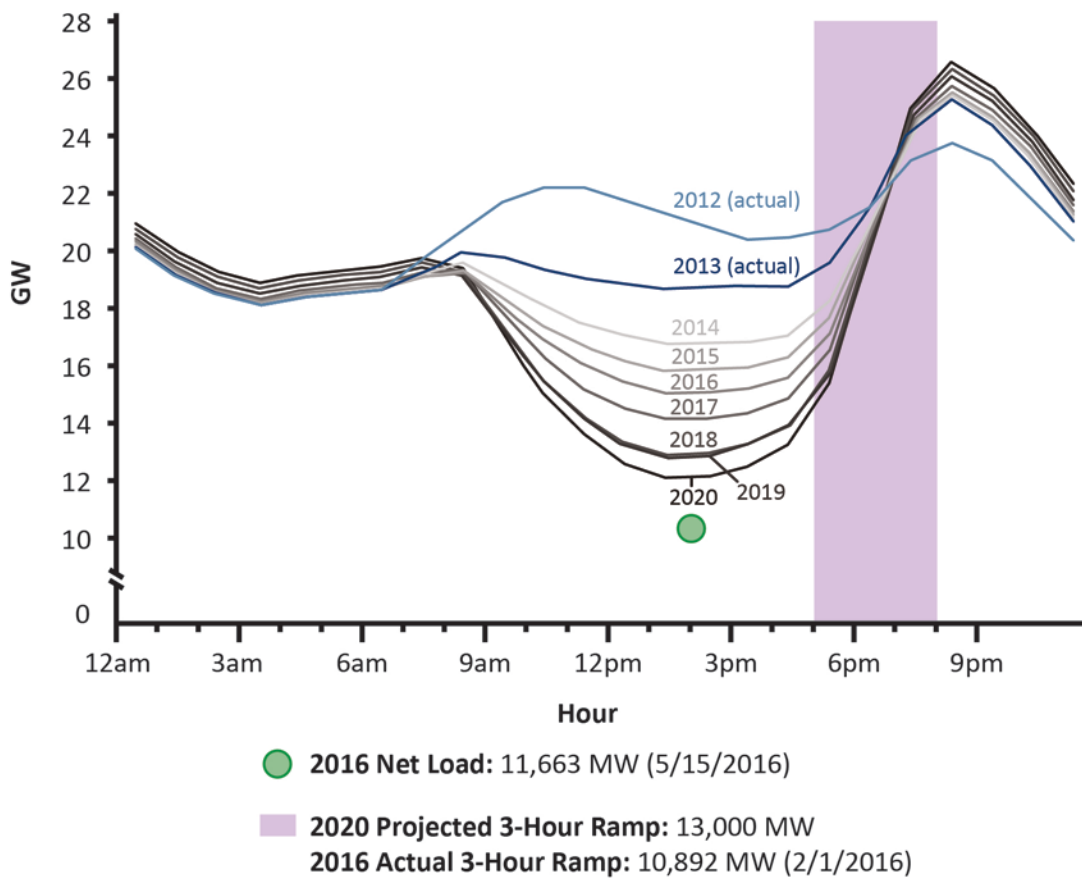


Figure 15: CAISO load profile.

DER Forecasting for Operations and Planning

Long-term DER forecasting for planning purposes must address both DER adoption or growth scenarios and the impact on net load of DER performance or autonomous behavior. Much of DER adoption and behavior may be characterized as autonomous, that is, driven by the needs of energy end users of all types whose interest is not in kWh per se but in the services they require at their residences and businesses. A challenge for planning is to forecast the adoption of various DER types over a planning horizon of ten years or more, with sufficient locational granularity for identifying and planning needed BPS infrastructure upgrades. In addition to adoption, however, planners also need to know how the performance or behavior of the DERs will affect the net load at each T-D interface, in terms of total energy, peak demand and load profile.

When DERs are comprised mainly of solar PV, forecasting behavior is manageable with good estimates of installed capacity by T-D interface and high-quality weather data. The composition of DERs will soon become more complex, however, with more widespread installation of storage devices, PV combined with battery storage and penetration of electric vehicles. With the addition of controllable DERs, such as storage devices, behavior becomes more difficult to predict and will depend on such things as retail rate structures (e.g., time of use or dynamic rates) and the possibility that DERs may be participating in the wholesale market or providing services to the distribution utility. Current proceedings underway at the California Public Utilities Commission are developing methods and provisions for DERs to substitute for distribution infrastructure investment and offer real-time operational services to the distribution utility. In many cases these will entail “multiple-use” applications where specific DERs may be located behind the retail meter to provide load management services to the customer, and may also provide services to the distribution utility, and may be aggregated across multiple sites to form a virtual resource that participates in the wholesale market.

Short-term forecasting of DER behavior has the same problems as long-term forecasting. In order for the CAISO to issue accurate dispatch instructions to balance supply and demand on the BPS, it needs accurate forecasts of net load at each T-D substation, looking ahead from 5 minutes to two or three hours. In this case, however, the installed capacity by resource type and T-D interface location should be well known to whichever entity is responsible for the forecast (distribution utility and/or BPS operator), as would any agreements between DER providers and distribution utilities for investment deferral or real-time services. Thus uncertainty about the adoption of DERs should not be part of the short-term forecasting problem.

Discussion

Reliable BPS operations requires grid operators to monitor the supply and demand balance and the state and availability of BPS elements, and the ability to accurately forecast the near term changes in load, availability of supply resources, state of transmission facilities, and external factors such as weather. This monitoring and forecasting is considered Situational Awareness and is required to dispatch the system and direct actions in response to unexpected disruptions. System dispatch relies on a sufficient quantity of generating resources under direct control to be able to provide voltage control, frequency support, and ramping capability as Essential Reliability Services (ERS) to balance and maintain the electric grid.

Traditionally, the basic grid operation is a free flowing transmission network connecting central station generation resources to load/demand buses with flow in a one-way direction to satisfy the load. The introduction of DERs challenges the basic model of BPS operations as the load/demand bus now may become a source, or at the very least, cause a reduction in demand at a load bus. In addition, as stated in previous sections, the nature and characteristics of the load/demand bus in models is changing, impacting the expected needs and response of the system.

As we explore the introduction of DER's into the electric system, several challenges become apparent:

- Transparency and observability of DER supply on the BPS
- Nature of the DER capabilities, typically inverter bases, ability to supply the ERSs, again as stated in previous sections
- Variability of the DER supply by its fuel source (typically renewable, or storage)
- Direct control of DER dispatch or inverter response
- The inverter impact modifying fault current

System operators that have relatively small quantities of DERs embedded within their system currently see very little direct impact as the variations observable at the BPS level are minor. On the other hand, where there are high penetrations of DERs, the system operator must consider the significant impacts on the ability to accurately forecast and control its system. The system operator must have adequate Situational Awareness and sufficient ERS levels to control the system reliably under all circumstances.

As seen in California, the growth in volume and diversity of DERs will require some expanded coordination arrangements and functional capabilities on the part of the distribution utilities and the BPS operator. The NERC ERS effort should continue to monitor these developments addressing T-D interface issues and needs of the BPS.

Appendix C: Review of Existing NERC Standards

As stated in the report, the DERTF has reviewed the list of standards below. The DERTF believes the flow of information relating to DERs from distribution entities to Transmission Owner/Operator and planning entities is already captured in these Reliability Standards (with the necessary adjustments to MOD-032 as noted in the report) and accounts for the impacts of DER on the T-D interface in planning and operations processes.

BAL-001 Real Power Balancing Control Performance

BAL-002 Disturbance Control Performance

BAL-003 Frequency Response and Frequency Bias Setting

BAL-005 Automatic Generation Control

CIP-002 Cyber Security – BES Cyber System Categorization

CIP-003 Cyber Security – Security Management Controls

CIP-005 Cyber Security – Electronic Security Perimeters

CIP-006 Cyber Security – Physical Security of BES Cyber Systems

CIP-008 Cyber Security – Incident Reporting and Response Planning

CIP-009 Cyber Security – Recovery Plans for BES Cyber Systems

CIP-010 Cyber Security – Configuration Change Management and Vulnerability Assessments

EOP-005 System Restoration Plans

EOP-011 Emergency Operations

FAC-001 Facility Interconnection Requirements

FAC-002 Facility Interconnection Studies

FAC-008 Facility Ratings

FAC-010 System Operating Limits Methodology for the Planning Horizon

FAC-011 System Operating Limits Methodology for the Operations Horizon

FAC-013 Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon

IRO-004 Reliability Coordination – Operations Planning

IRO-005 Reliability Coordination – Current Day Operations

IRO-010 Reliability Coordinator Data Specification and Collection

MOD-001 Available Transmission System Capability

MOD-004 Capacity Benefit Margin

MOD-008 Transmission Reliability Margin Calculation Methodology

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

MOD-012-0 Dynamics Data for Modeling and Simulation of the Interconnected Transmission System

MOD-016-1.1 Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, and Controllable Demand-Side Management

MOD-017-0.1 Aggregated Actual and Forecast Demands and Net Energy for Load

MOD-019-0.1 Reporting of Interruptible Demands and Direct Control Load Management

MOD-020-0 Providing Interruptible Demands and Direct Load Control Management Data to System Operators and Reliability Coordinators

MOD-021-1 Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts

MOD-025 Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

MOD-026 Verification of Models and Data for Generator Excitation Control System and Plant Volt/Var Control Functions

MOD-027 Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

MOD-028 Area Interchange Methodology

MOD-031 Demand and Energy Data

MOD-032 Data for Power System Modeling and Analysis (replaces MOD-010)

MOD-033 Steady-State and Dynamic System Model Validation (replaces MOD-012)

PRC-004 Protection System Misoperation Identification and Correction

PRC-006 Automatic Underfrequency Load Shedding

PRC-008 Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program

PRC-010 Undervoltage Load Shedding

PRC-011 Undervoltage Load Shedding System Maintenance and Testing

PRC-018 Disturbance Monitoring Equipment Installation and Data Reporting

PRC-019 Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls and Protection

PRC-020 Under-Voltage Load Shedding Program Database

PRC-021 Under-Voltage Load Shedding Program Data

PRC-022 Under-Voltage Load Shedding Program Performance

PRC-024-2 (pending) Generator Voltage and Frequency Protective Relay Settings

PRC-027 Coordination of Protection Systems for Performance During Faults

TOP-001 Transmission Operations

TOP-002 Operations Planning

TOP-003 Operational Reliability Data

TOP-004 Transmission Operations

TOP-005 Operational Reliability Information

TPL-001 Transmission System Planning Performance Requirements

VAR-001 Voltage and Reactive Control

VAR-002 Generator Operation for Maintaining Network Voltage Schedules

Appendix D: Transmission-Distribution Interface

As noted in Chapter 1, demand side management (DSM) resources can affect the aggregate characteristics, modeling requirements, and potential BPS reliability impacts at the T-D interface. While DSM activities may not have the same characteristics or behaviors as resources that produce electricity, DSM activities can have impacts at the T-D interface that overlap and interact with those of DERs.

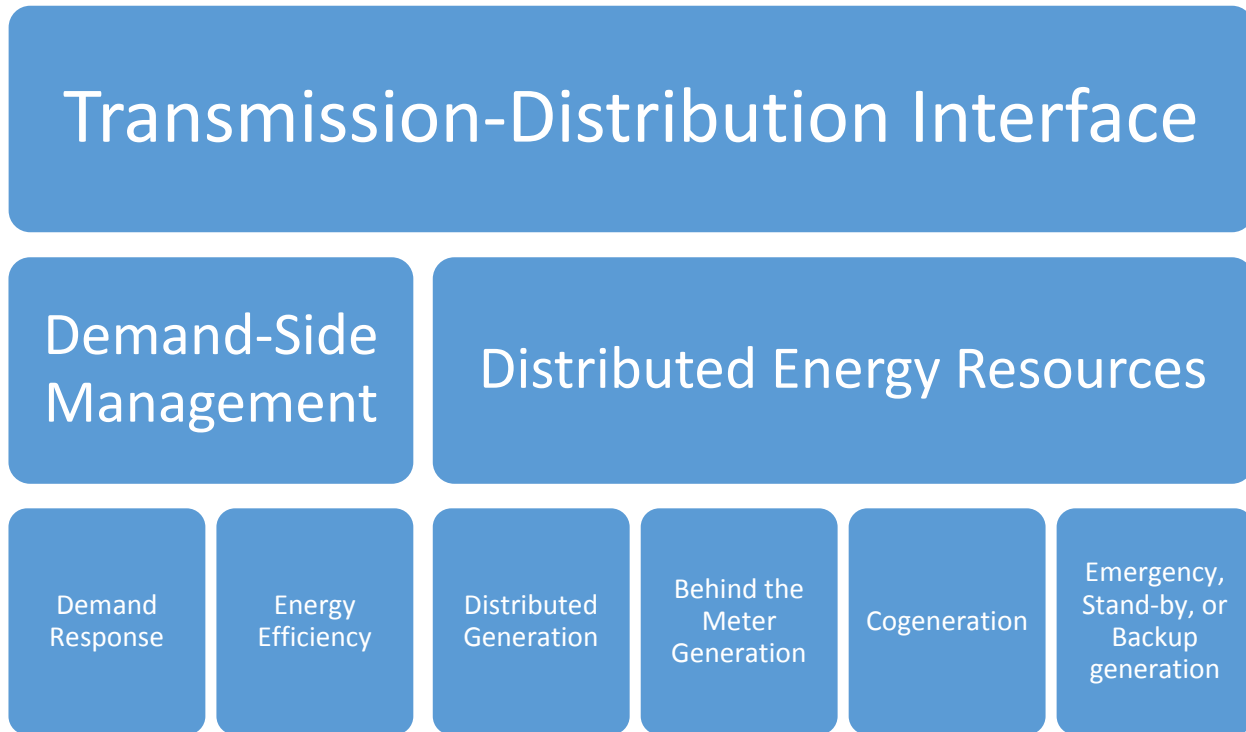


Figure 16: Relationship between DSM resources and DERs at the T-D interface.

Task Force Membership

Name	Entity
Gerald Beckerle	Ameren
Dave Canter	American Electric Power
Jim Fletcher	American Electric Power
Richard Hydzik	Avista Corporation
Clyde Loutan	California Independent System Operator
Lorenzo Kristov	California Independent System Operator
Brant Werts	Duke Energy
John Hughes	Electricity Consumers Resource Council
Robert Enriken	Electric Power Research Institute
Aidan Tuohy	Electric Power Research Institute
Jens Boemer	Electric Power Research Institute
Jack Cashin	Electric Power Supply Association
Julia Matevosyan	Electric Reliability Council of Texas
Alfred Corbett	Federal Energy Regulatory Commission
Hassan Hamdar	Florida Reliability Coordinating Council
Jason McDowell	General Electric
Nicholas Miller	General Electric
Sasoon Assaturian	Independent Electricity System Operator
John Simonelli	Independent System Operator of New England
Patricia Poli	Michigan Public Service Commission
Mike McMullen	MISO
Barry Mather	National Renewable Energy Laboratory (NREL)
Paul McCurley	National Rural Electric Cooperative Association
Mark Ahlstrom	NextEra Energy
Robert Cummings	North American Electric Reliability Corporation
Michelle Marx	North American Electric Reliability Corporation
John Moura	North American Electric Reliability Corporation
Ryan Quint	North American Electric Reliability Corporation
Pooja Shah	North American Electric Reliability Corporation
Elliott Nethercutt	North American Electric Reliability Corporation
Lee Pedowicz	Northeast Power Coordinating Council
Quoc Le	Northeast Power Coordinating Council
Gary Keenan	Northwest Power Pool
Dariush Shirmohammadi	California Wind Energy Association
Todd Lucas	Southern Company
Sylvester Toe	Southern Company
Thomas Siegrist	Stone, Mattheis, Xenopoulos & Brew, P.C.
Jagan Mandavilli	Texas Reliability Entity
Brian Evans-Mongeon	Utility Services
Anthony Jankowski	WE Energies
Layne Brown	Western Electricity Coordinating Council

References

- [1] E. van Ruitenbeek, J.C. Boemer, J.L. Rueda, and M. Gibescu et al., “A Proposal for New Requirements for the Fault Behaviour of Distributed Generation Connected to Low Voltage Networks,” presented at the 4th International Workshop on Integration of Solar Power into Power Systems, Berlin, Germany (10-11 November, 2014). Edited by Uta Betancourt and Thomas Ackermann. Langen: Energynautics GmbH, 2014, <http://integratedgrid.com/wp-content/uploads/2016/07/van-Ruitenbeek-Boemer-et-al.-2014-A-Proposal-for-New-Requirements.pdf>.
- [2] J.C. Boemer, “On Stability of Sustainable Power Systems: Network Fault Response of Transmission Systems with Very High Penetration of Distributed Generation,” Dissertation, Intelligent Electrical Power Grids, Delft University of Technology, June 2016, <http://doi.org/10.4233/uuid:78bffb19-01ed-48f9-baf6-ffb395be68a0>.
- [3] Transmission System Planning Performance Requirements (NERC TPL-001-4), NERC, 2014.
- [4] WECC Data Preparation Manual for Steady-State and Dynamic Base Case Data. WECC System Review Work Group. Western Electricity Coordinating Council: October 2014, but as of writing, this is in the process of being replaced by the WECC Data Preparation Manual for Interconnection-wide Cases Applicable to the 2017 Base Case Compilation Schedule, <https://www.wecc.biz/Reliability/WECC-Data-Preparation-Manual-Rev-7-Approved.pdf>.
- [5] Steady State and Dynamic Data Requirements MOD-(11 and 13)-WECC-CRT-1 Regional Criterion. WECC. Western Electricity Coordinating Council: June 26, 2013.
- [6] WECC Solar Power Plant Dynamic Modeling Guidelines. WECC Renewable Energy Modeling Task Force. Western Electricity Coordinating Council: April 2014, <https://www.wecc.biz/Reliability/WECC%20Solar%20Plant%20Dynamic%20Modeling%20Guidelines.pdf>.
- [7] Standard for Interconnecting Distributed Resources with Electric Power Systems (IEEE Std. 1547-2003). IEEE Standards Coordinating Committee 21, 2003.
- [8] Small Generator Interconnection Procedures (SGIP). For Generating Facilities No Larger Than 20 MW. RM13-2-000. FERC. September 19, 2009.
- [9] Small Generator Interconnection Agreement (SGIA). For Generating Facilities No Larger Than 20 MW. RM13-2-000. FERC. September 19, 2009.
- [10] California Public Utility Commission, “ELECTRIC RULE NO. 21: GENERATING FACILITY INTERCONNECTIONS,”. Accessed April 24, 2012, http://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_21.pdf.
- [11] J.C. Boemer, A. Huque, B. Seal, and T. Key et al., “Status of Revision of IEEE Std 1547 and 1547.1: Informal report based on IEEE P1547/Draft 5.0 (August 2016),” presented at the 6th International Workshop on Integration of Solar Power into Power Systems, Vienna, Austria.
- [12] Draft Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems (IEEE P1547/D3). IEEE Standards Coordinating Committee 21, 2016, http://grouper.ieee.org/groups/scc21/1547_revision/1547revision_index.html.
- [13] Requirements for Frequency and Voltage Ride Through Capability of Small Generating Facilities. Notice of proposed rulemaking (NOPR). Docket No. RM16-8-000. FERC. March 17, 2016.
- [14] Interim Decision Adopting Revisions to Electric Tariff Rule 21 For Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to Require “Smart” Inverters, California Public Utilities Commission, December 18, 2014. Accessed January 21, 2015 at <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M143/K827/143827879.PDF>.

-
- [15] J.C. Boemer, and J. Suckow, "Status of revision of the VDEARN 4105 Application Guide for the Connection of Distributed Generation to Low Voltage Networks," presented at the 6th International Workshop on Integration of Solar Power into Power Systems, Vienna, Austria.
- [16] German Government, "Verordnung zu Systemdienstleistungen durch Windenergieanlagen (Systemdienstleistungsverordnung – SDLWindV) (Ordinance for Ancillary Services of Wind Power Plants (Ancillary Services Ordinance - SDLWindV)," Federal Law Gazette I (no. 39) (2009): 1734–46, <http://www.erneuerbare-energien.de/inhalt/43342>.
- [17] WECC Wind Power Plant Dynamic Modeling Guide. WECC Modeling and Validation Work Group. Western Electricity Coordinating Council: April 2014.
- [18] Wind turbines - Part 27-1: Electrical simulation models – Wind turbines (IEC 61400-27-1). IEC ICS 27.180:2015, 2015.
- [19] Proposed Changes to the WECC WT3 Generic Model for Type 3 Wind Turbine Generators. P. Pourbeik: Issued: 03/26/12 (revised 6/11/12, 7/3/12, 8/16/12, 8/17/12, 8/29/12, 1/15/13, 1/23/13, 9/27/13). Prepared under Subcontract No. NFT-1-11342-01 with NREL.
- [20] Proposed Changes to the WECC WT4 Generic Model for Type 4 Wind Turbine Generators. P. Pourbeik: Issued: 12/16/11 (revised 3/21/12, 4/13/12, 6/19/12, 7/3/12, 8/16/12, 8/17/12, 8/29/12, 1/15/13, 1/23/13). Prepared under Subcontract No. NFT-1-11342-01 with NREL.
- [21] J. Fortmann, N. Miller, Y. Kazachkov, and J. Bech et al., "Wind Plant Models in IEC 61400-27-2 and WECC - Latest Developments in International Standards on Wind Turbine and Wind Plant Modelling," presented at the 14th International Workshop on Large-Scale Integration of Wind Power into Power Systems as well as on Transmission Networks for Offshore Wind Power Farms, Brussels, Belgium (22-23 October, 2015). Edited by T. Ackermann and U. Betancourt., 2015.
- [22] WECC Guide for Representation of Photovoltaic Systems In Large-Scale Load Flow Simulations. WECC Modeling and Validation Work Group. Western Electricity Coordinating Council: January 2011.
- [23] Technical Guidelines for Power Generating Units: Part 4 -Demands on Modelling and Validating Simulation Models of the Electrical Characteristics of Power Generating Units and Systems. FGW. FGW e.V. Fördergesellschaft Windenergie und andere Erneuerbare Energien, Kiel. 7th ed.: April 07, 2014.
- [24] P. Kundur, Power system stability and control. New York: McGraw-Hill, Inc., 1994.
- [25] IEEE Recommended Practice for Excitation System Models for Power System Stability Studies (IEEE Std 421.5-2005). IEEE, 2006.
- [26] F. Edwards, G. Dudgeon, J. McDonald, and W. Leithead, "Dynamics of distribution networks with distributed generation," presented at the 2000 IEEE Power Engineering Society Summer Meeting, Seattle, Washington, USA (16 - 20 July, 2000). Vol. 2, 1032-1037 vol. 2. Piscataway, NJ: IEEE Service Center, 2000.
- [27] R. Guttromson, "Modeling distributed energy resource dynamics on the transmission system," Power Systems, IEEE Transactions on 17 (no. 4) (2002): 1148–53. doi:10.1109/TPWRS.2002.804957.
- [28] T. Tran-Quoc, L. Le Thanh, C. Andrieu, and N. Hadjsaid et al., "Stability Analysis for the Distribution Networks with Distributed Generation," presented at the 2005/2006 IEEE PES Transmission and Distribution Conference and Exhibition, Dallas, TX (21 - 24 May, 2006). 1-3, 289–94. Piscataway, NJ: IEEE, 2006.
- [29] J. Klimstra, "Fault ride-through capability of engine-driven power plants," presented at the 2009 POWER-GEN Europe, Koelnmesse, Cologne, Germany (26 - 28 May 2009, 2009). Edited by PennWell. PennWell, 2009.

-
- [30] J.C. Boemer, M. Gibescu, and W.L. Kling, "Dynamic Models for Transient Stability Analysis of Transmission and Distribution Systems with Distributed Generation: an overview," presented at the IEEE PowerTech, Bucharest, Romania (June 28 – July 2, 2009). Edited by IEEE., 2009.
- [31] F.O. Resende, J. Matevosyan, and J.V. Milanovic, "Application of dynamic equivalence techniques to derive aggregated models of active distribution network cells and microgrids," presented at the 2013 IEEE Grenoble PowerTech, Grenoble, France (16-20 June, 2013), 1–6., 2013.
- [32] E. Muljadi, C.P. Butterfield, A. Ellis, and J. Mechenbier et al., "Equivalencing the collector system of a large wind power plant," presented at the 2006 IEEE Power Engineering Society General Meeting, Montreal, Quebec., Canada (2006), 9 pp., 2006.
- [33] S. Mat Zali, and J.V. Milanovic, "Generic Model of Active Distribution Network for Large Power System Stability Studies," IEEE Transactions on Power Systems, 2013. doi:10.1109/TPWRS.2012.2233223, <http://ieeexplore.ieee.org/ielx5/59/4374138/06403906.pdf?tp=&arnumber=6403906&isnumber=4374138>.
- [34] J.V. Milanovic, and S. Mat Zali, "Validation of Equivalent Dynamic Model of Active Distribution Network Cell," IEEE Transactions on Power Systems 28 (no. 3) (2013): 2101–10. doi:10.1109/TPWRS.2012.2227844.
- [35] S. Sugita, Y. Kataoka, S. Naoi, and Y. Noro et al., "Study of modeling method of distributed generators considering partial dropout for trunk transmission system," presented at the 2010 International Power Electronics Conference-ECCE Asia, Sapporo, Japan (June 21-24, 2010), 975–80. [Piscataway, N.J.]: IEEE, 2010.
- [36] R.T. Elliott, A. Ellis, P. Pourbeik, and J.J. Sanchez-Gasca et al., "Generic photovoltaic system models for WECC - A status report," presented at the 2015 IEEE PES General Meeting, Boston, MA (26-30 July, 2015), 1–5., 2015.
- [37] Generic Solar Photovoltaic System Dynamic Simulation Model Specification. WECC Renewable Energy Modeling Task Force. Western Electricity Coordinating Council: September 2012.
- [38] Analysis of Voltage and Frequency Performance of the Bulk System with High Levels of Variable Generation and Distributed Energy Resources: Case Studies and Lessons Learned. EPRI. Electric Power Research Institute (EPRI), Palo Alto, CA: February 2016. 3002007496, <http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002007496>.
- [39] CIGRÉ Working Group C4.605. Modelling and Aggregation of Loads in Flexible Power Networks: Final Report. 2014. TB 566.
- [40] Composite Load Model for Dynamic Simulations. WECC Modeling and Validation Work Group. Western Electricity Coordinating Council. Report 1.0: June 12, 2012.
- [41] J.C. Boemer, E. Vittal, M. Rylander, and B. Mather, "Determination of WECC Distributed PV System Model Parameters for Partial Loss of Generation Due to Bulk System Voltage Sags," presented at the 6th International Workshop on Integration of Solar Power into Power Systems, Vienna, Austria.
- [42] B. Mather and F. Ding, "Distribution-connected PV's response to voltage sags at transmission-scale," presented at the 2016 IEEE Photovoltaic Specialist Conference, Portland, OR (5-10 June, 2016), pp. 1–6., 2016.
- [41] Standard for Interconnecting Distributed Resources with Electric Power Systems, Amendment 1, IEEE Std. 1547a-2014. IEEE Standards Coordinating Committee 21, 2014.