NATF Reference Document: Distributed Energy Resource Modeling and Study Practices

Version 1.0 (Open)
Approval Date: 06/20/2018

Versioning

Version History

Date	Version	Notes
06/20/2018	1.0 (Open)	Original version for public release

Review and Update Requirements

- Review: every 5 years
- Update: as necessary

Contents

1. Introduction

1.1 Purpose of the Document

In early 2017, the North American Electric Reliability Corporation (NERC) Distributed Energy Resource Task Force (DERTF) developed a report [1] that described, at a high level, distributed energy resources (DER) modeling recommendations for bulk power system (BPS) planning studies. Under the same framework and principal, the NERC Load Modeling Task Force (LMTF) has released a series of "technical reference documents" [2] and "reliability guidelines" on load and DER modeling [3-4]. The reliability guideline on DER modeling [4] provided detailed information for developing models and model parameters to represent different types of utility-scale DER (U-DER) and retail-scale DER (R-DER) in stability analysis of the bulk power system.

The purpose of this reference document is to provide additional details that will help power system planners or study engineers to prepare the DER models for:

1. interconnection-wide power flow cases and dynamic simulations;
2. DER impact assessments on the bulk power system.

This document specifically focuses on the distributed generation (DG), typically photovoltaic resources, component of DER.

The reference document also provides examples of DER modeling and studies that have been conducted across North American utilities to assess DER impacts on the transmission system.

1.2 Distributed Energy Resources (DER) Definitions

Distributed energy resources (DER) are defined differently, but commonly include renewable energy generation, energy storage, electric vehicles, demand response, and demand-side management (e.g. conservation programs and energy efficiency devices). This broad definition of DER is demonstrated by the following figure.

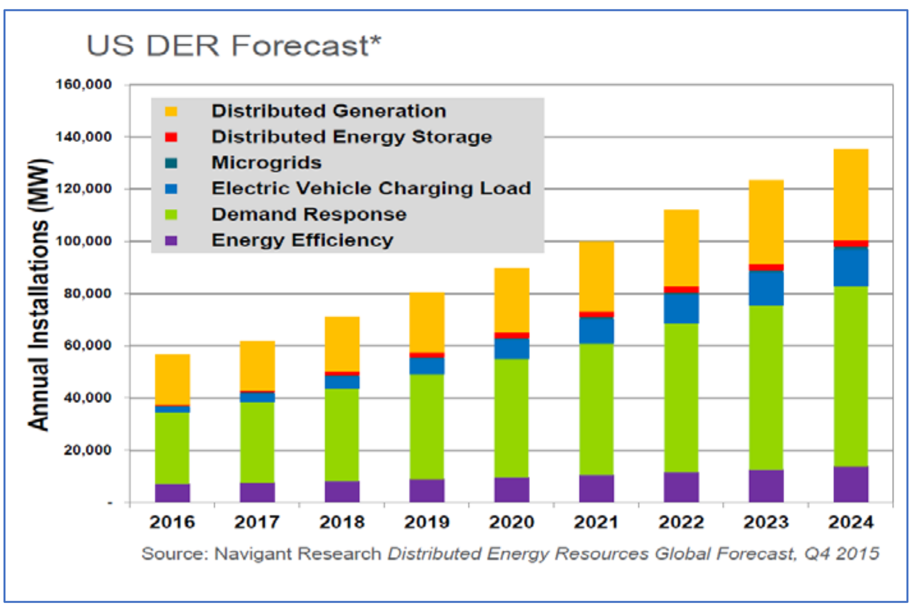


Figure 1.1. US DER Forecast (Courtesy of Navigant Research DER Global Forecast, Q4 2015)

The NERC DER technical report [1] provides an overview of the typical connections of DER at distribution systems.

When it comes to the discussions of modeling and studies, this document, to be consistent, will use the same DER definitions as defined in the NERC DER modeling reliability guideline [4].

- Utility-Scale DER (U-DER): DER directly connected to the distribution bus or connected to the distribution bus through a dedicated, non-load serving feeder. These resources are specifically three-phase interconnections, and can range in capacity, for example, from 0.5 to 20 MW, although facility ratings can differ.
- Retail-Scale DER (R-DER): DER that offsets customer load. These DER include residential, commercial, and industrial customers. Typically, the residential units are single-phase while the commercial and industrial units can be single- or three-phase facilities.

Standalone DERs connected to busses that are load-serving feeders and are not covered by the above definitions in the NERC document, can be included with U-DER if their location is relatively close (i.e., several busses away) to the substation or with R-DER if their location is closer to customer load sites (e.g., secondary and tertiary branches of the feeder).

2. DER Growth

2.1 US Solar Growth Trends

DERs have continued to grow around the world due to a combination of economic incentives, pro-renewable energy policies, and decreasing cost of technology (especially PV and storage). Germany has seen explosive growth in distribution-connected solar, where installed PV capacity has grown by more than 35 GWs in the last decade [39]. The map below compares United States (US) solar potential to Germany based on solar irradiance levels. From this map, it is evident that the US has a much greater solar energy potential. Given the right economic incentives and market conditions, DER penetration in the US can increase rapidly and is anticipated to surpass levels seen in Germany and other countries.

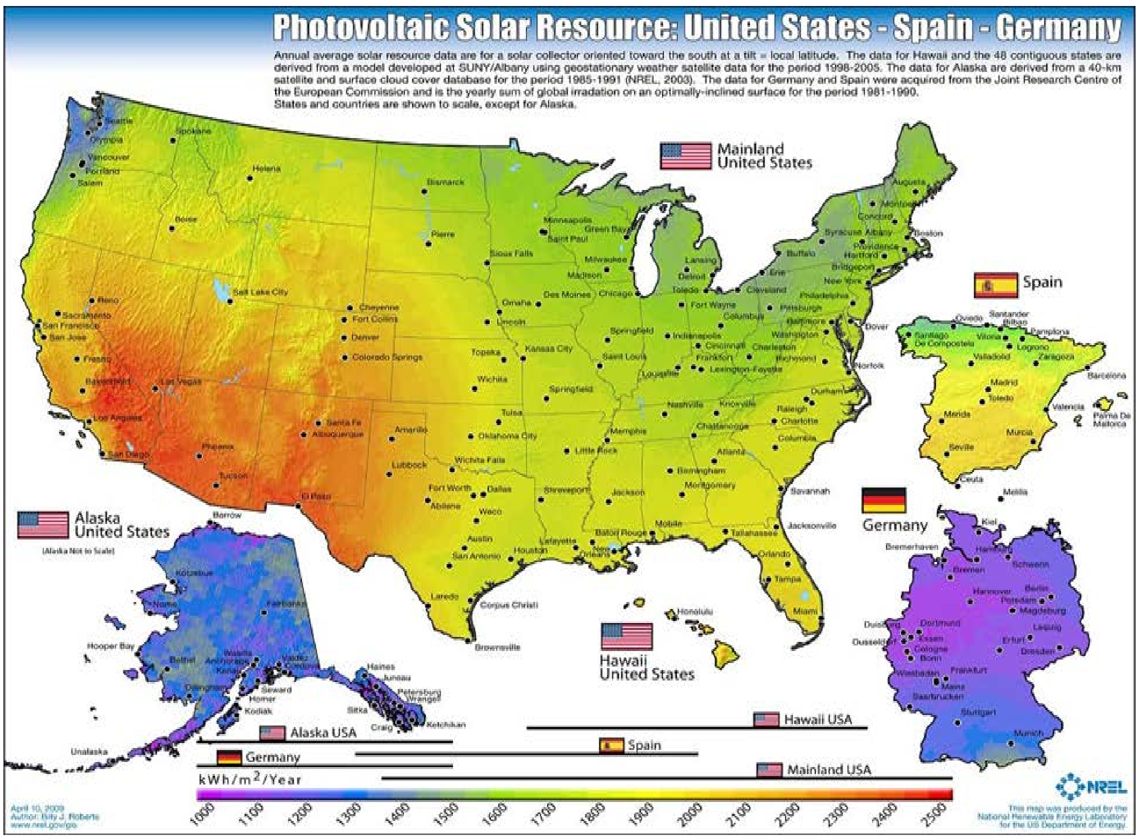


Figure 2.1. US Solar Potential (Courtesy of NREL)

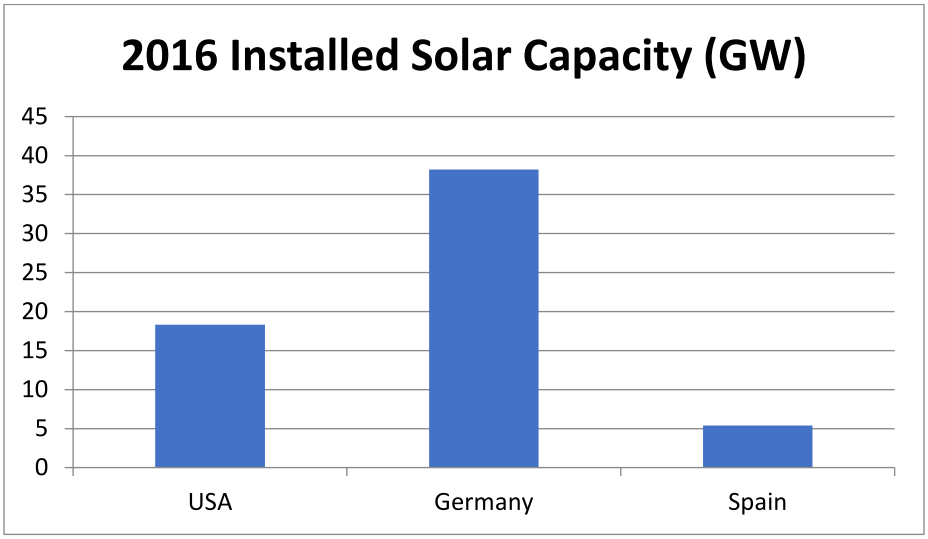


Figure 2.2. US, Germany, Spain 2016 Installed Solar Capacity [5]

The figures below show growth and projections of solar PV in the US as well as the top ten states in the US by installed MW capacity as of early 2017.

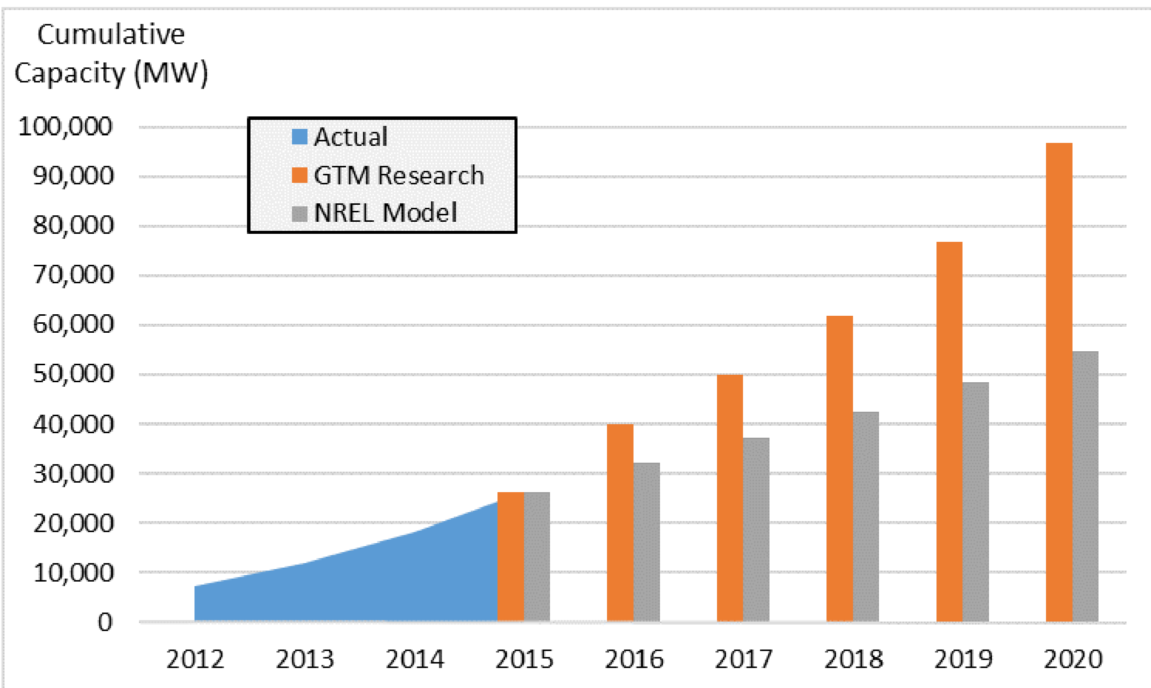


Figure 2.3. US Solar Growth and Projections: Cumulative Capacity [6]

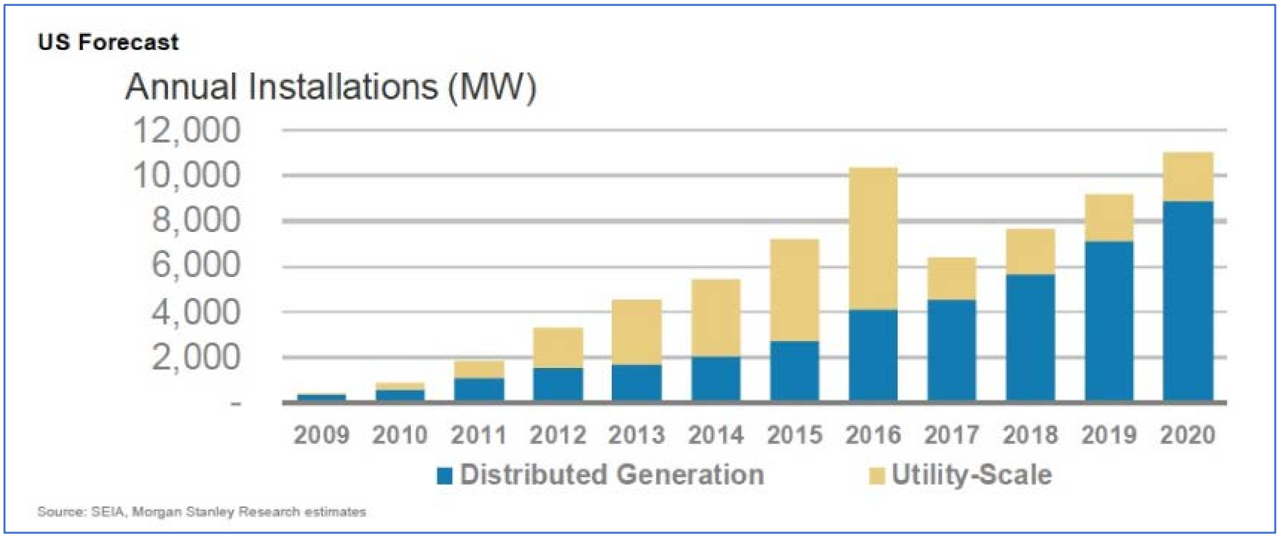


Figure 2.4. US Solar Growth and Projections: Cumulative Capacity [7]

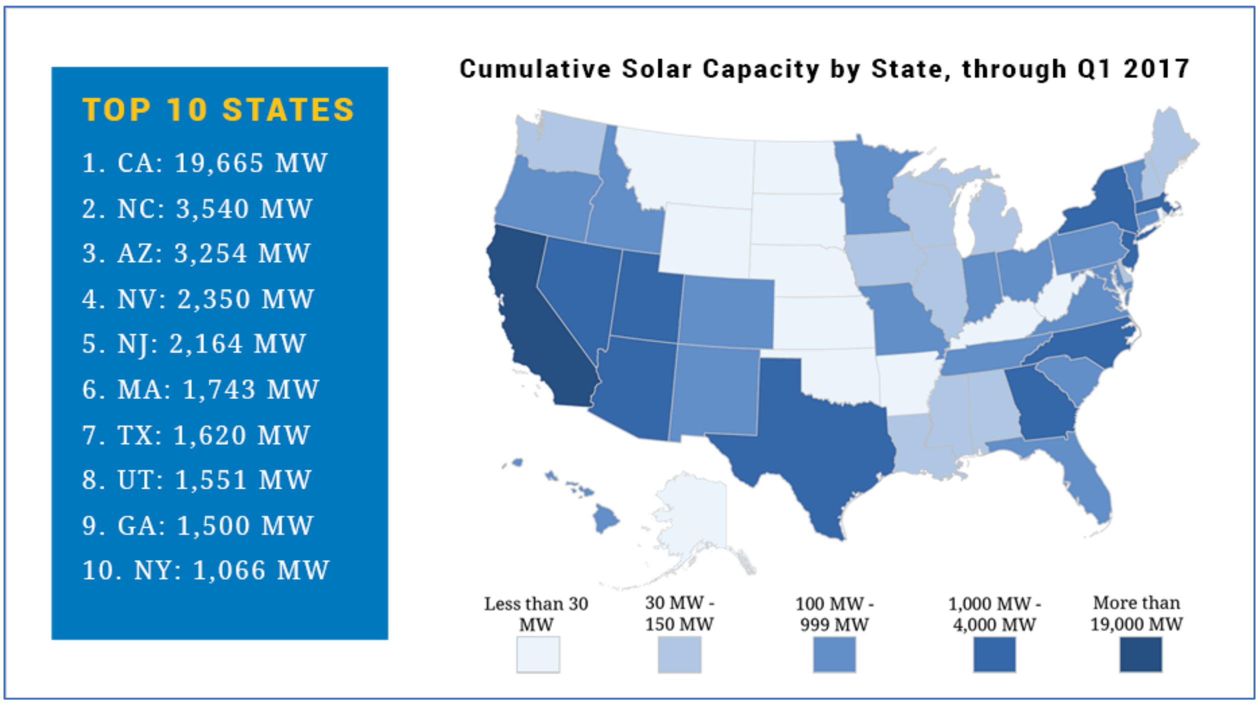


Figure 2.5. Top 10 States in US by Installed Capacity [8]

2.2 Utility-Specific Projected Solar Growth Trends

The following two graphs are examples from Duke Energy and CAISO showing projections of PV for the next 10 years.

The Duke Energy 2017 Integrated Resource Plan [9] for North and South Carolina incorporate the solar capacity forecast shown in the chart below. While a majority of current solar capacity is connected to Duke Energy's distribution systems, it is expected that a majority of future additions will be larger plants connecting to Duke Energy's transmission systems. This solar forecast includes a 0.5% per year degradation of total solar megawatt (MW) output from the existing (installed) resources.

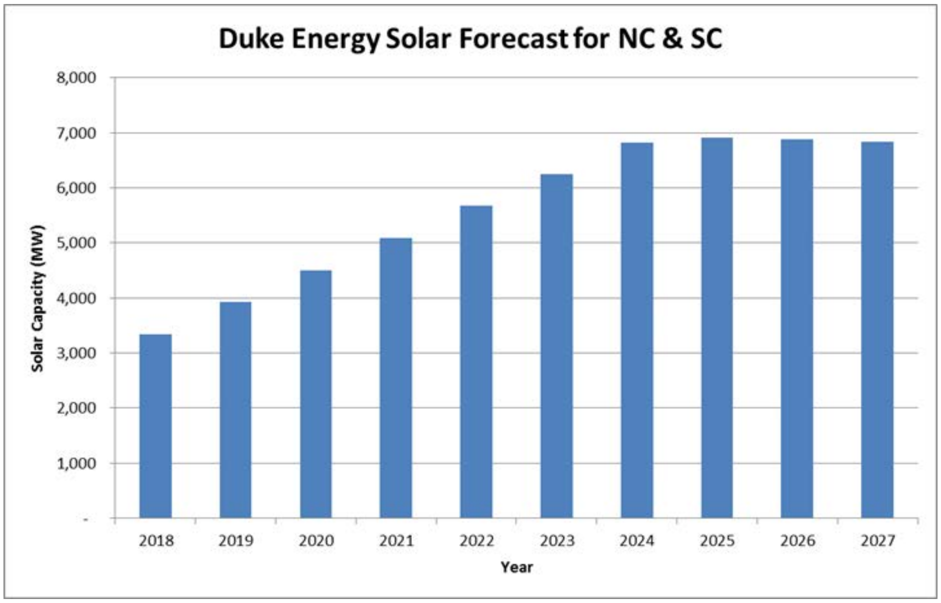


Figure 2.6. Duke Energy Solar Forecast for North Carolina & South Carolina [9]

The CAISO behind-the-meter (BTM) solar forecast shown in the chart below is based on data from a CAISO study [10].

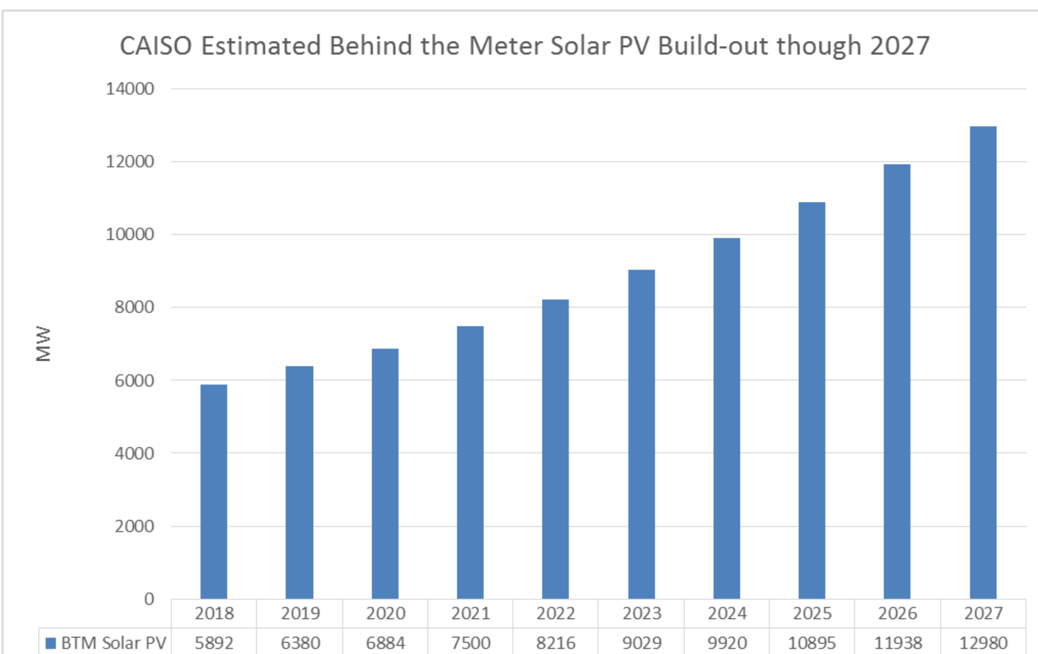


Figure 2.7. CAISO BTM Solar Forecast [10]

3. DER Planning and Operational Challenges

DER industry standards, such as IEEE Std. 1547-2003, have been in existence for more than a decade and continue to evolve; however, challenges in DER planning and operation are still emerging as a result of the increasing penetration of DER and technology advancement [11]. This section will highlight some DER planning and operational challenges for transmission owners and operators.

3.1 DER Planning Challenges

DERs are studied and integrated into the distribution system by distribution planners. A transmission planner's involvement with DER integration may include determining hosting capacities at a bus, station, or area level and identifying transmission asset upgrade needs. In current practices, limited DER data are available to transmission planners and detailed modeling of DER components is omitted in transmission planning studies, and this lack of data availability has created challenges for transmission planning. The following issues require consideration by transmission planners when the level of DER penetration into the transmission system is considered high.

Planning Data

DER integration may require the following data for extended planning studies in addition to the standard generator data such as nominal voltage, capacity (Pmin/Pmax, Qmin/Qmax), and type of generation:

- **DER control mode and respective parameters**: Power-factor-based control is the most frequently used control strategy in existing DER; however, planners may have options to configure volt-var, watt-var, volt-watt, watt-Hz, and other control modes for new DER installations.
- **Distribution feeder characteristics**: Distribution feeders are typically not modeled in transmission planning studies; however, they may have material impact on DER operation when the penetration level is high (e.g., unacceptable over-voltages). With increasing distribution facilities modeled in transmission planning studies, the lower X/R ratio of the distribution system may cause issues with the decoupled Newton-Raphson power-flow solver. Integrated or hybrid transmission-distribution simulation schemes have been researched to address these solution issues [12-13].
- **Fault contribution**: Maximum fault contribution from DERs should be provided by manufacturers and is needed for equipment ratings and protective relay verification. Fault contribution from inverter-based DERs may only slightly exceed the resources rated current. Inverter-control philosophy may also affect fault contributions. Generic assumptions based on conventional generation could be overly conservative in identifying the need of asset upgrades.
- **Capacity and coincidence factors**: Wind and PV DER outputs are subject to season and weather conditions. Transmission planning based on DER nameplate capacity may be oversimplified. Aggregated MW output due to variable weather conditions or DER protective control settings may contribute to a reduction in total realized output. Therefore, historically reported capacity factor and coincidence factor should be collected for planning studies. For example, maximum wind output is more likely to coincide with off-peak demand at night. On the other hand, minimum wind output is often associated with peak demand, which for summer-peaking systems can be in hot and humid weather. Solar DER output may be better correlated with system demand but its maximum

output is typically prior to the daily peak hour. Further discussions on DER output assumptions in system studies can be found in Section 6.

- **Voltage or frequency-based protection and control settings**: These settings may be embedded in the DER dynamic model and are necessary to be included for high-penetration DER planning studies. In contrast to synchronous generating resources, existing inverter-based DER have a higher probability of being tripped off-line due to their voltage and frequency ride-through capabilities.

Modeling

Aggregation of distribution-level DER can present challenges to the transmission planner when determining how to accurately reflect the DERs in the transmission-planning models. These challenges relate to how to define the specific parameters for discrete DER resources that are modeled as a single aggregated DER resource in the transmission planning models. This is particularly an issue when it comes to representing the protection and control settings in the aggregated DER model used in the transmission planning studies. The recent development of DER modeling practice is discussed in Section 5.

Studies

In regions with high levels of DER penetration, the temporal and seasonal variability of DER adds another dimension to the types of system conditions that need to be analyzed by transmission planners. PV generation, in particular, increases the complexity of the studies and total number of studies needed to adequately assess the potential risks to the transmission system and its protective equipment. Traditional peak-load, valley-load, and high-transfer conditions may need to be augmented by additional scenarios considering combinations of DER and customer load that might stress the transmission system.

In the past, generators connected to distribution systems were rarely considered in dynamic stability analysis since they were typically too small to cause power oscillation or instability in the grid. However, the increasing DER penetration into the grid with considerable aggregate rating has made dynamic stability studies more relevant to bulk power system stability studies.

Section 6 elaborates on the scenarios to be considered in DER planning studies.

Study Tools

The existing commercially available software tools may not be sufficient to accommodate the issues as discussed in the above sections of the report. Timely upgrades in power system study tools are needed to accommodate the DER data, modeling, and study needs. For example:

- Power flow study tools need to accommodate the volt-var, watt-var, volt-watt, and other operating modes in DER connected under new standards or codes;
- The positive-sequence-based representation of DER may not reflect the inverter-based DER ride-through behavior in real operations, including momentary cessation;
- Probabilistic planning tools may be required for transmission system assessment due to the intermittent nature of DER output.

DER Forecast

DER forecast information is needed for planning studies; however, some utilities may include the DER in their demand forecasts. NERC guidelines and reports point to the non-netting of DER with load forecasts as the preferred practice for developing DER forecast.

The NATF DER Modeling Group conducted a survey on utility forecast practice in summer 2016 [14]. A total of 37 responses were received. The survey indicated the following:

- About half of the respondents explicitly consider demand-side (behind the customer meter) distributed generation in the development of their load forecasts.
- About half of the respondents explicitly consider utility-side distributed generation in the development of their load forecasts.
- For those respondents that explicitly consider demand-side (behind the customer meter) distributed generation in the development of their load forecasts, most utilities have the distributed generation netted as part of the load, and half of them indicated that they are explicitly looking to represent the distributed generation as opposed to netting it against the load in the near term.
- For those respondents that explicitly consider utility-side distributed generation in the development of their load forecasts, some have distributed generation netted in the load, some modeled distributed generation as a set of discrete resources at the T/D interface, and others modeled distributed generation as a single aggregated resource at the T/D interface.

IOUs in California have an explicit DER forecast separate from the demand forecast. Reference [15] [16] are examples on forecasting assumptions and frameworks by California IOUs (PG&E, SCE, and SDG&E).

3.2 DER Operational Challenges

A variety of research studies have been published on various DER operation issues. These issues may include anti-islanding, power quality, protection coordination, resonant instability, etc. However, utility operators still see differences among applied research, industry standardization, and power system implementation. The following challenges arising from practical DER operations need immediate solutions.

Observability and Controllability

DERs below a certain MW capacity threshold may not be monitored and thus not visible to system operators. It can be expensive, and potentially cost prohibitive, to integrate these micro-DERs into the host utility's energy management system (EMS), but the aggregated invisibility has introduced new challenges to grid operators, particularly complicating resource prediction and system dispatch. The ability to dispatch DER resources depends on state regulations and utility contract terms and conditions. More frequently, DER withdrawals or the reduction in their MW output is due to their own protective control settings or weather conditions and are therefore considered uncontrollable from a system-operators perspective.

Another issue of concern is the response of DERs to system disturbances such as switching transients, resonance, or faults that may cause DERs to temporarily cease operation. There is a potential risk for DERs to trip off concurrently during major transmission system disturbances if the DERs are electrically downstream of a passive anti-islanding scheme (i.e., based on voltage or frequency). Such an uncontrollable loss of DER may jeopardize post-fault system recovery performance and requires coordination between anti-islanding and ride-through settings. Figures 3.1 and 3.2 show responses of a 44 kV type-III wind farm and a 44 kV solar farm, respectively, under a single-phase to ground fault at a remote 500 kV bus. The transmission fault caused voltage sags at the DER connection points for approximately three cycles. It can be seen that both the DERs ceased injecting current to the grid apparently by their internal protections or protective controls. The wind DER (fig. 3.1) stopped current injection after the transmission fault had been cleared (after t=50ms in fig. 3.1 when connecting point voltages were fully restored). The solar DER (fig. 3.2) initiated shutdown during the fault (at t=40ms when the voltage sags were still shown in voltage waveforms, the meters at the two farms are not time synchronized). This transmission fault event tripped off multiple DERs across a wide area.

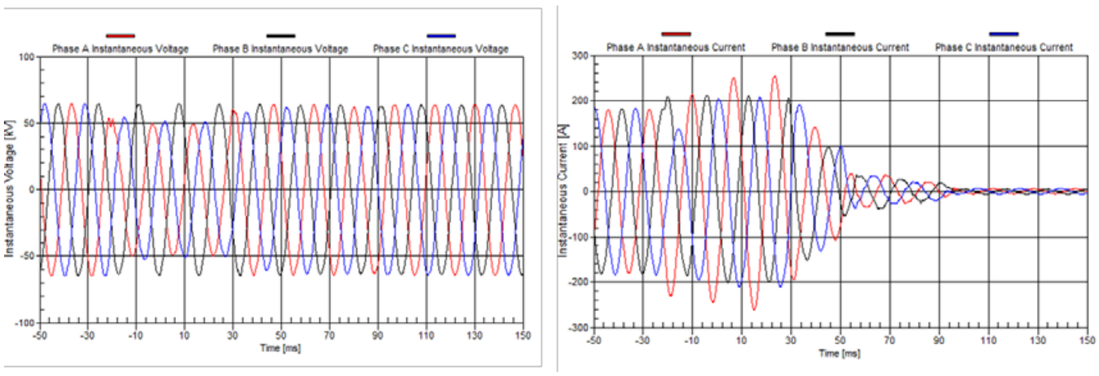


Figure 3.1. Voltage and Current Waveforms of a 44 kV Wind Farm under Remote 500 kV Fault

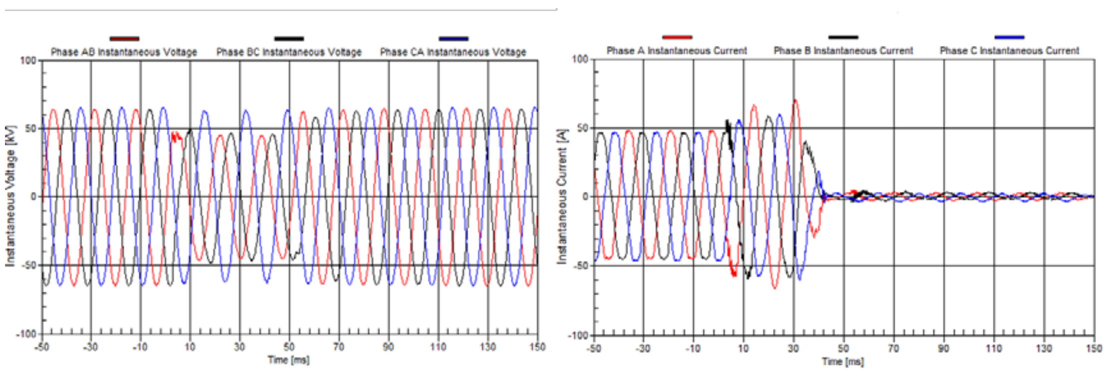


Figure 3.2. Voltage and Current Waveforms of a 44 kV Solar Farm under Remote 500 kV Fault

Bi-Directional Power Flow

Increased DER connections can change the typical power flow patterns in the transmission system. Figure 3.3 shows an example of a 230 kV / 44 kV substation where the capacity of solar generators connected to the 44 kV feeders has exceeded the station loads. As a result, the active power flowing through the step-down transformers is bi-directional, or zero. The load-flow snapshot in figure 3.3 shows zero amps of current flowing through the transformer (i.e., both the active and reactive power were perfectly balanced in the 44 kV network). SCADA data indicated the zero-flow lasted for more than 20 minutes without noticeable fluctuation. Such a scenario imposes operational risks of sustained unintentional islanding if the transformer breaker inadvertently opened. The existing anti-islanding schemes cannot identify this specific situation. New operating procedures may need to be established in order to manage this type of risk. For example, the 22-Mvar shunt capacitor in figure 3.3 may be removed preemptively so that the island would collapse quickly due to reactive power shortage.

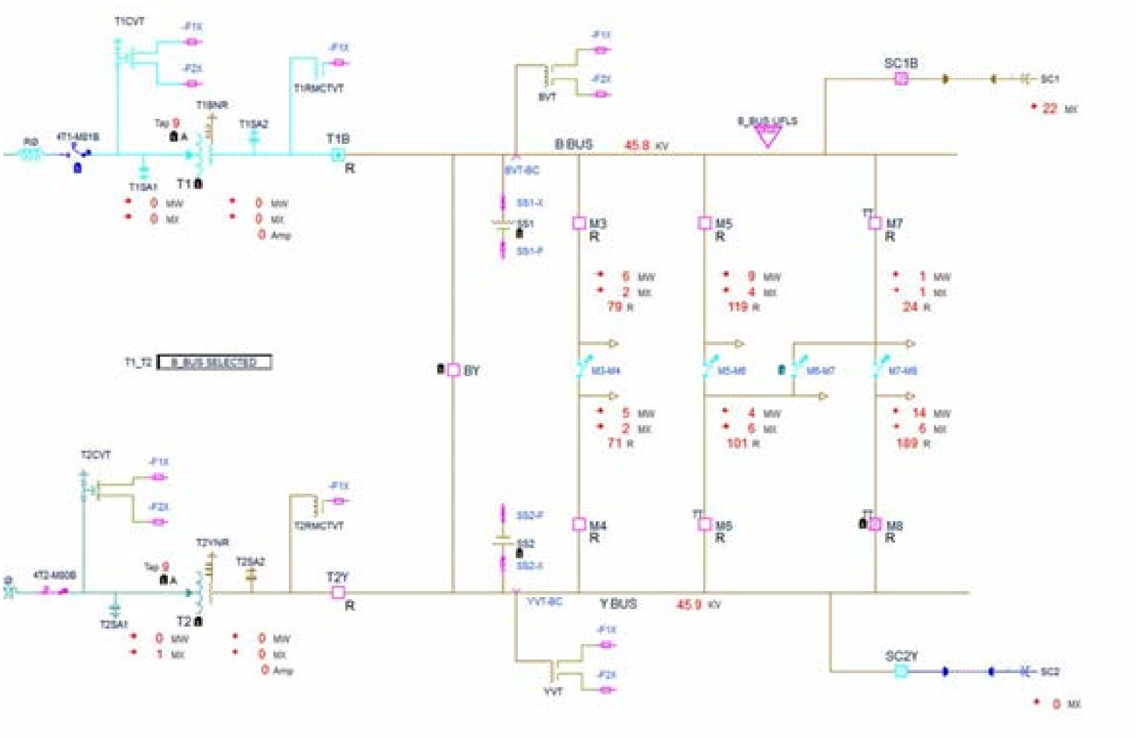


Figure 3.3. Zero Flow at Transmission Substation Due to DER Solar

Figure 3.4 shows MW flow through one of the transformers in figure 3.3 during a typical summer week, where the negative MW indicates power flow from the 44 kV system into the 230-kV system. Some issues to be addressed for this example of reversed power flow may include:

- **Voltage regulation**: Some voltage-regulating equipment may be designed based on power flows from the direction of grid source only. Some equipment may have reverse power detection and actuation capability but mainly for classical load transfer condition (where the new load side is still supplying load only). Where a reversal of power flow through such equipment is caused by DERs, the voltage may be adjusted improperly. Voltage regulators with line drop compensation may require additional attention since reverse power flow through this type of voltage regulator may create worse voltage profiles. Voltage-regulation equipment control modification or replacement may be needed to accommodate reverse power flow [17].
- **Transformer reverse power capability**: When transformer power direction is reversed due to DERs, the voltage on the secondary winding could exceed the limit, which is designed for load supply operation only [17]. In some transformers with dual LV windings, if one LV winding carries reversed power from DERs but the other LV winding supplies normal load, the power may actually circulate from one LV winding to the other with minimum power flow from the HV winding. Some vintage

transformers have very limited capability for such circulation. Planners may consult transformer manufacturers to establish reverse power limit through their equipment.

- **Over-voltage of equipment**: DER installations acceptable under peak load conditions have caused voltage rises exceeding acceptable limits under off-peak load conditions, most likely to occur when the DER is injecting power into the electric power system (EPS) [17]. In some cases, the normally in-service capacitors previously for power factor correction are retrofitted as automatically switchable to manage the over-voltage. The voltage rises due to reverse flow of power is illustrated in next section.
- **Protection**: Reverse flow or back-feeding through feeder protection by DERs have created sympathetic tripping for faults on adjacent feeders. Protection functions and settings need to be evaluated for the reverse power impact.

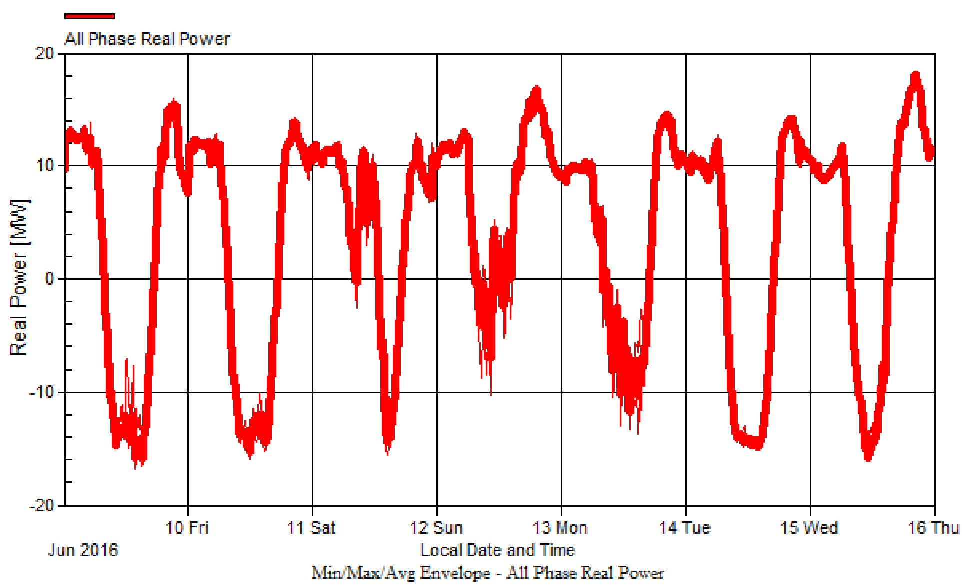


Figure 3.4. MW Flow through the Substation Transformer

Overvoltage

DERs are often operated at unity power factor. This may cause over-voltage at distribution feeders due to lower X/R ratios in the distribution system. This can be illustrated with a simplified distribution feeder with DER connected as shown in figure 3.5. Figure 3.6 plots the point of common coupling (PCC) voltages versus DER delivering power at unity power factor with various feeder X/R ratios. It can be seen that the voltage variation increases as the X/R ratio decreases. Figure 3.6 also shows that the PCC voltage will vary more in a weaker connection (i.e., higher per unit active power based on fault level at PCC). The voltage variations could result in excessive operation of a line regulator or tap changer or switching of a capacitor bank. Planners should consider the sensitivity to the X/R ratio when determining DER hosting capacity. Higher levels of DER penetration could be restricted by the voltage variation range unless an automatic voltage regulating facility, such as STATCOM, or energy storage is applied to the feeder. Transmission buses may also experience overvoltage issues under reduced load conditions when active power is injected into the transmission system by DERs.

In order to manage the overvoltage, a DER may be required to operate at a leading power factor, which may assist in managing a voltage drop under the sudden loss of a DER.

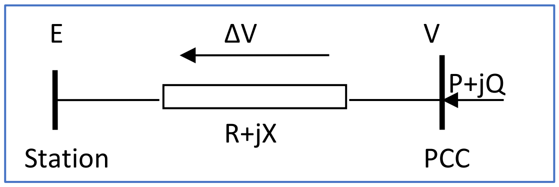


Figure 3.5. Distribution System with DER Connection

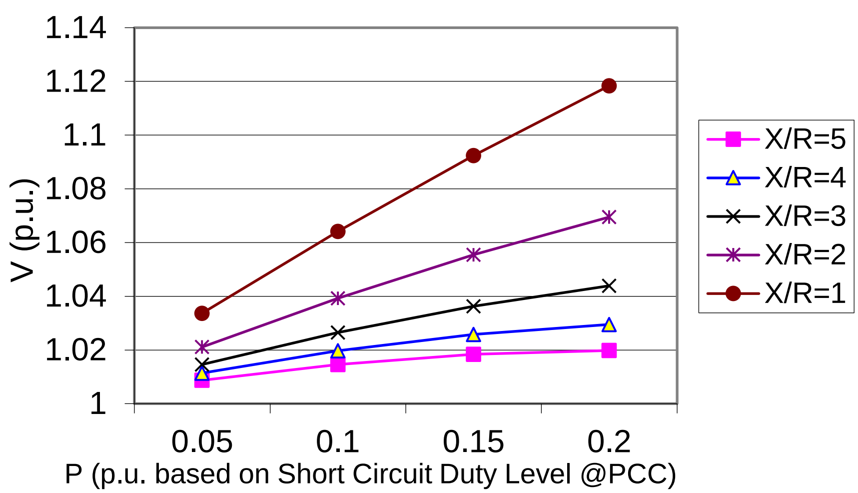


Figure 3.6. PCC Voltage Variations with DER Injection at Unity Power Factor

Short Circuit

Fault current contribution from DERs could vary widely among different generator types, manufacturers, and control philosophies [18]. While synchronous-generation DER could contribute several times its full load current under a fault, inverter-based DER may only contribute slightly higher than its full load rating. The inverters may even initiate a shutdown during a fault either by its own protective control design or passive anti-islanding settings. Figures 3.7, 3.8, and 3.9 show the responses of a 28 kV type-4 wind, type-3, wind, and PV DER to a single-phase to ground 230 kV transmission system fault, respectively. It can be seen that the output currents during the fault are significantly different although their reduction in terminal voltage are similar.

The increased fault current from aggregated DER contribution, combined with existing system fault contribution, may exceed some electric power system (EPS) equipment ratings, such as station breakers, or exceed grid code limits. However, realistic generation coincidence should be considered to avoid overly conservative decisions of needed facility upgrades. For example, full DER outputs may require some conventional generation to be dispatched off.

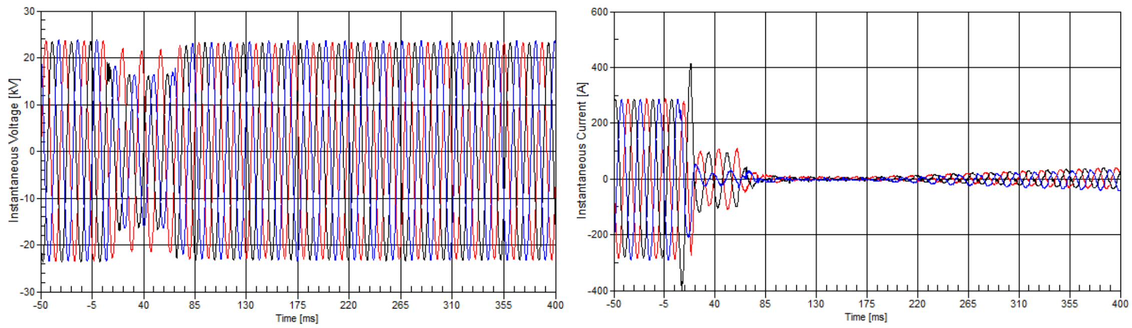


Figure 3.7. Voltage and Current of a 28 kV Type-4 Wind Farm under a 230 kV Fault

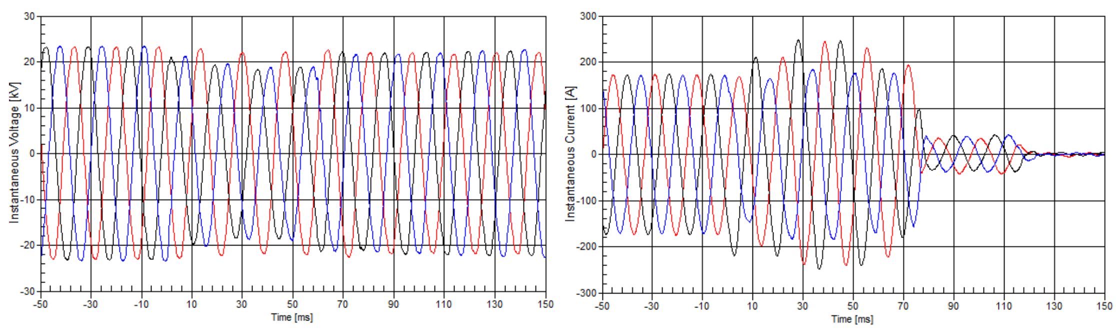


Figure 3.8. Voltage and Current of a 28 kV Type-3 Wind Farm under a 230 kV Fault

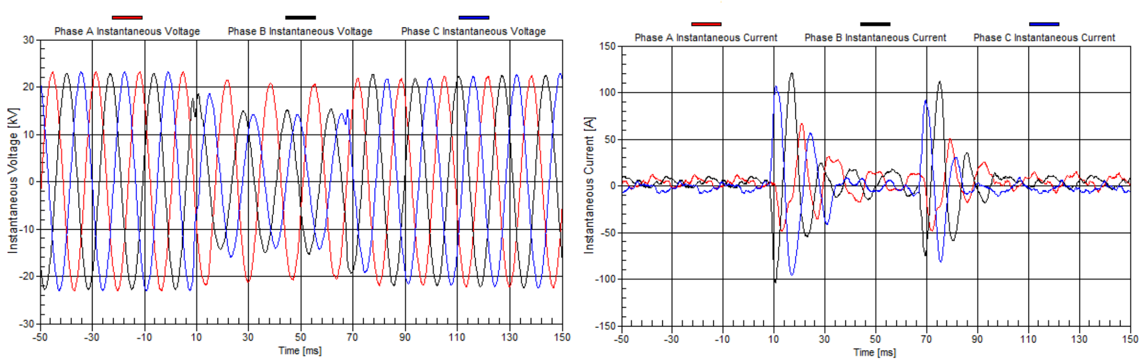


Figure 3.9. Voltage and Current of a 28 kV Solar Farm under a 230 kV Fault

Protection Coordination

The short circuit contribution from DERs may either over-sensitize or desensitize overcurrent-based protection. The type of energy source, interface to the grid, and grounding configuration of the interconnection transformer are sensitive parameters for protection studies. Distance-based feeder protection has been applied in areas with high penetration of DERs and has achieved consistent performance. Protection coordination could be simpler if the DER interface transformer does not provide a source of zero sequence current; however, temporary overvoltage risks need to be assessed when the DER is isolated with the feeder during a single-line-to-ground fault. At high levels of DER penetration, fast auto-reclosing settings should be coordinated with the anti-islanding schemes to avoid reclosing to facilities still energized by DERs. Figure 3.10 shows a 28 kV feeder trip and auto-reclosing while a type-I wind farm sustained the feeder island prior to substation breaker reclosing. Figure 3.11 shows the zoomed details of voltage phase angle jumps under such “out-of-phase” reclosing.

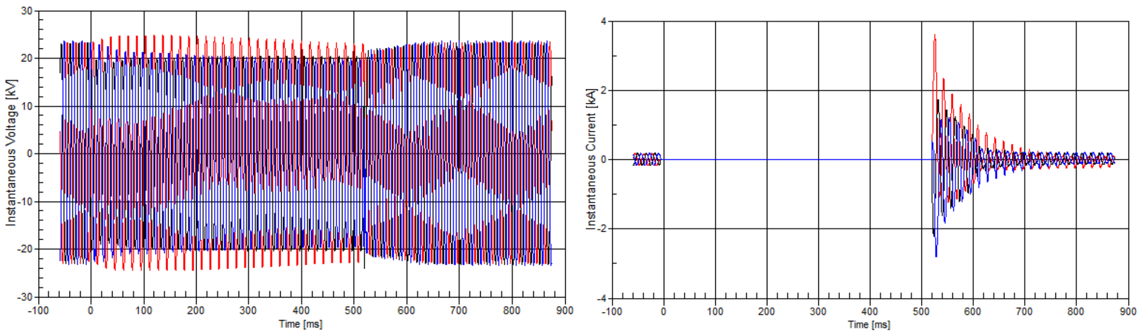


Figure 3-10. Voltage and Current of a 28 kV Feeder under Islanding and Reclosing

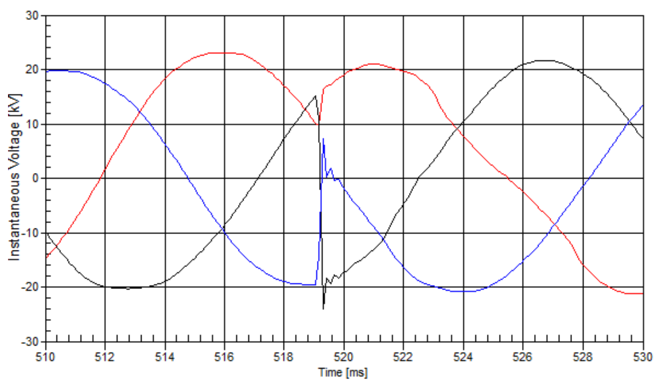


Figure 3.11. Zoom-in of Voltage Phase Jump during Reclosing

Under-frequency load shedding (UFLS) also needs to be reassessed when DER penetration is high. UFLS should be coordinated such that feeders without DERs or with very light DER capacity are shed first. Shedding major DER generation at the same time as load may cause further frequency decline. Existing UFLS designs may be reconfigured so that feeders with high penetration of DERs are not included in the scheme. To deal with changing penetration over time, active power flow direction could be monitored by UFLS relays, with positive (not reverse) load flow enabling relay action.

Figure 3.12 shows a voltage waveform record of a 44 kV island after separating from the 115 kV transmission grid [19]. The DER output was equal to approximately 25% of the load prior to the islanding. The low generation-to-load ratio should have collapsed the island rapidly. However, a UFLS scheme was activated and tripped several feeders in the island; as a result, the voltage and frequency declines were paused at 0.6 seconds. Though the example was originally intended to highlight the importance of coordination between UFLS and DER anti-islanding, it also shows the effect of DER in a real under-frequency situation.

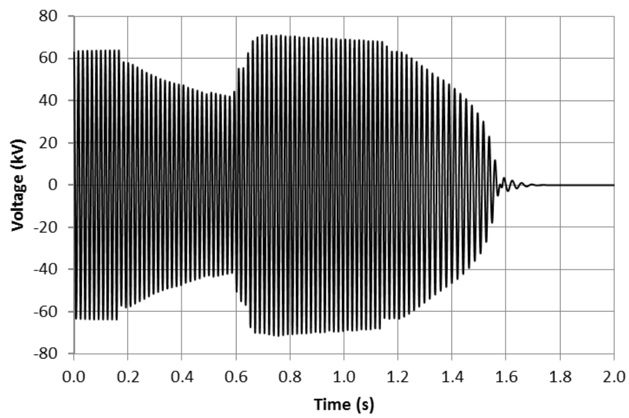


Figure 3.12. Example of UFLS and DER Coordination

Reliability and Safety Concerns

From a safety perspective, it is important that DERs be electrically isolated from the distribution system so that under a forced outage condition on the transmission system the DERs do not back-feed into either the distribution or transmission systems. Insulation coordination is another consideration associated with the installation of DERs.

Other concerns:

- The DER facility design must provide for the synchronization of the DER to the distribution system.
- DERs without synchronizing capabilities must be disconnected from the distribution system prior to reconnecting the distribution system to the transmission system.
- The design of the DER must remove all potential back-feed sources from the distribution system prior to the transmission system breaker reclosing.

Forecasting

Increased penetration of DERs also present challenges for gross and net load short-term forecasting [20]. System operators need accurate short-term forecasts to operate their systems reliably and to run real-time wholesale markets. One example of the challenge today is that many DERs do not participate in the ISO markets as supply resources but "self-dispatch" as load modifiers, altering the overall load shape and making load forecasting difficult. As a result, system operators have less certainty about whether sufficient resources are available and committed to serve load and maintain system stability.

4. DER Performance Standards

In the last decade, the bulk transmission system resource mix has been changing as the result of the integration of renewable resources (primarily wind and solar), additional natural gas fired generation, and the retirement of coal and some nuclear generation. As a result of this transformation, the development of DER performance standards has gained momentum in many countries.

The table below provides a summary of standards/guidelines, which have different limits on the sizes of DERs:

Table 4.1. Overview of Applicable DER Size by Standards

Standard/Guideline	DER Size Limit
IEEE 1547 (2003/2014 Amendment)	Aggregate 10 MVA at the Point of Common Coupling (PCC)
IEEE 1547 (current revision)	No limit. Standard only for Distribution facilities
FERC SGIA	Up to 20 MW
NERC DER Modeling Guideline	No limit. For Transmission Facilities
CA Rule 21	Up to 20 MW. Standard for Distribution Facilities

In the US, the IEEE 1547 standard group and California's Rule 21 work group are currently developing performance guidelines for facilities connected at the distribution level.

IEEE 1547

The IEEE 1547 standard covers the technical specifications for, and testing of, the interconnection and interoperability between utility's distribution electric power systems (EPS) and distributed energy resources (DERs). The standard also provides requirements relevant to the performance, operation, testing, safety, and maintenance of the interconnection. It also includes general requirements, response to abnormal conditions, power quality, islanding, and specifications and requirements for design, production, installation evaluation, commissioning, and periodic testing. The requirements are comprehensive and address the interconnection of DERs, including synchronous machines, induction machines, and power inverters/converters and will suffice for most installations. The criteria and requirements are applicable to all DER technologies interconnected to EPSs at typical primary and/or secondary distribution voltages. Installation of DERs on radial primary and secondary distribution systems is the main emphasis of this document, although installation of DERs on primary and secondary network distribution systems is considered. The standard is written considering that the DER is connected to a 60 Hz source. [21]

California Rule 21

Electric Rule 21 is a tariff that describes the interconnection, operating, and metering requirements for generation facilities to be connected to a utility's distribution system within the state of California that fall under the jurisdiction of the California Public Utilities Commission. The tariff provides customers wishing to install generating or storage facilities on their premises the requirements to access the electric grid while protecting the safety and reliability of the distribution and transmission systems at the local and system levels. [22]

The table below is a comparison of advanced functions required by various standards applicable in North America [23].

Table 4.2. Comparison between Various Standards Applicable in North America [23]

		Interconnection Standards			State/ PUC Rules		Listing/ Certification		
Function set	**Advanced Functions Capability**	**IEEE 1547-2003**	**IEEE 1547a-2014**	**IEEE 1547 - 2018***	**CA Rule 21 - 2015**	**HI Rule 14H - 2015**	**UL 1741**	**UL 1741(SA) 2016**	**IEEE 1547.1-201?***
Static	Adjustable Trip Settings		√	‡					Δ
Controlling	Active Power Curtailment			‡					Δ
	Disable Permit Service (Remote Shut-Off)			‡					Δ
	Ramp Rate Control				‡	‡		Δ	
Freq. Support	L/H Frequency Ride-Through			‡	‡	‡		Δ	Δ
	ROCOF Ride-Through			‡					Δ
	Frequency-Watt	X	√	‡		‡		Δ	Δ
Voltage Support	L/H Voltage Ride-Through (L/H VRT)			‡	‡	‡		Δ	Δ
	Dynamic Voltage Support during L/H VRT			√					
	Voltage Phase Angle Jump Ride-Through			‡					Δ
	Fixed Power Factor	√	√	‡	‡	‡	√	Δ	Δ
	Fixed Reactive Power	√	√	‡			√		Δ
	Volt-Var	X	√	‡	‡	‡		Δ	Δ
	Volt-Watt	X	√	‡		‡		Δ	Δ
	Watt-Var	X		‡					Δ

** Final requirements not confirmed.*

Legend: X Prohibited, √ Allowed by Mutual Agreement, ‡ Capability Required, Δ Test and Verification Defined

One of the advanced functions of primary interest to transmission system planners is the voltage and frequency ride-through aggregated capability and response of the DER units.

As an example, IEEE 1547 frequency ride-through requirements are shown below in figure 4.1.

IEEE 1547 is recommending that frequency disturbances of any duration, for which the system frequency remains between 58.5 Hz and 60.6 Hz and the per-unit ratio of voltage/frequency is less than or equal to 1.1, shall not cause the DER to trip. The DER shall remain in operation during such disturbances and shall be able to continue to exchange active power at least as great as its pre-disturbance level of power.

For frequency disturbances for which the system frequency is less than 58.5 Hz and greater or equal to 57.0 Hz in accordance with the above graph, the DER shall be capable to ride through, maintain synchronism with the transmission system, and maintain its pre-disturbance active power output depending on the DER category.

During high-frequency disturbances where the frequency of the system is greater than 60.6 Hz and less than 62.0 Hz in accordance to the graph below (figure 4.1), the DER shall maintain synchronism with the transmission grid, continue to exchange current and modulate active power to mitigate the over-current conditions.

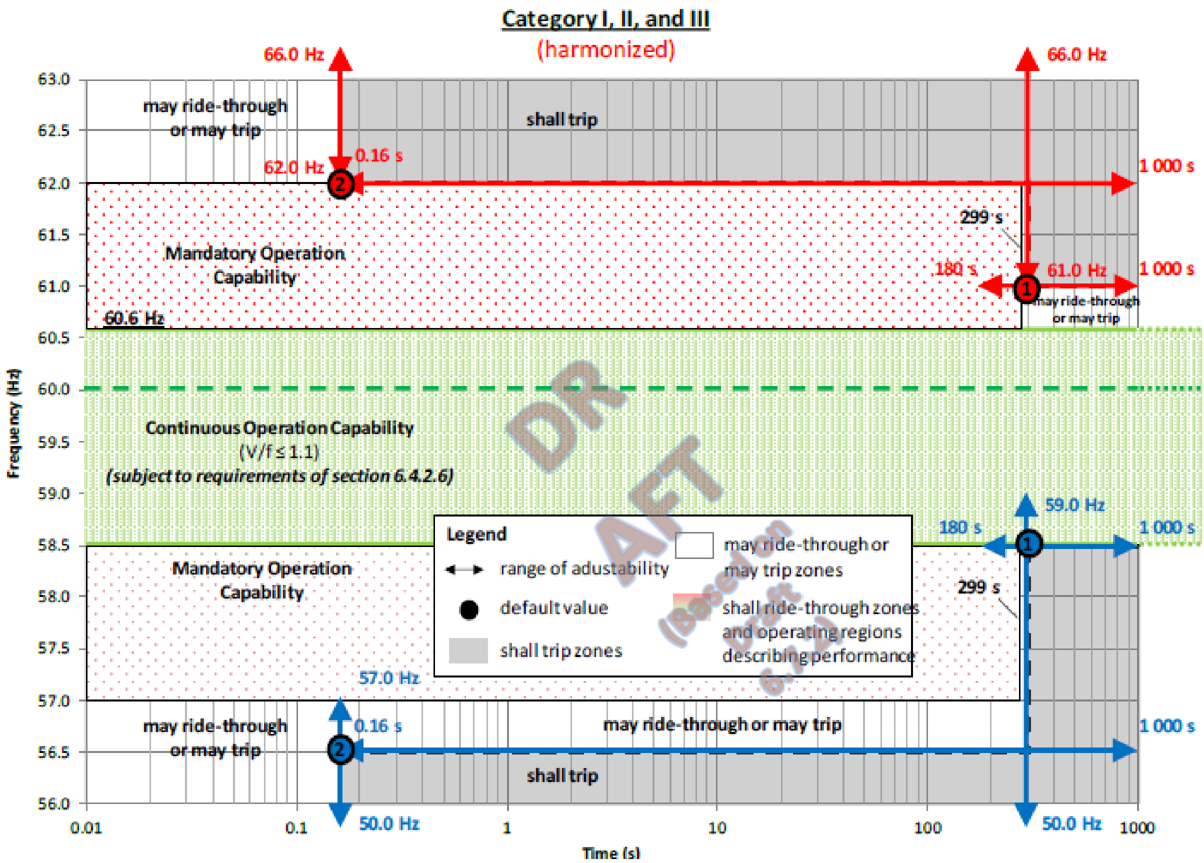


Figure 4.1. IEEE 1547 Frequency Ride-Through Requirements

The table below provides a comparison of the voltage and frequency ride-through requirements among IEEE 1547, CA Rule 21, and NERC PRC-024-1. It is important to note that outside the No Trip Zone of PRC-024-2 is a "may trip" area, meaning that tripping is not required, and protection should be widened to the greatest extent while still protecting the inverter. IEEE 1547 uses a "Must Trip" zone outside the "No Trip Zone." This has been a significant source of confusion, which was discovered from the two recent system-wide loss-of-PV events, and currently being addressed in the NERC IRPTF [40].

Table 4.3. Comparison of Ride-Through Requirements

Standard	CA Rule 21	IEEE 1547	PRC-024-1
Gen Size	Not Specified	10 MW and below	Greater than 20 MVA[1]
Connection	Distribution	Distribution	BES (100 kV and above)
Ride-Through	Yes	Yes	Yes
V ≥ 1.20	Instantaneous Trip	0.16	Instantaneous Trip
1.175 < V < 1.20	12	1-13	0.2
1.15 < V < 1.175	12	1-13	0.5
1.10 < V < 1.15	12	1-13	1
0.90 ≤ V ≤ 1.10	Indefinite	Indefinite	Indefinite
0.88 ≤ V < 0.90	Indefinite	Indefinite	3
0.75 ≤ V < 0.88	20	2-20	3
0.70 ≤ V < 0.75	20	2-20	2
0.65 ≤ V < 0.70	10	0.32-10	2
0.50 ≤ V < 0.65	10	0.32-10	0.3
V < 0.50	1	0.16 - 1	0.15
f > 62	Instantaneous Trip	0.16	Instantaneous Trip
61.7 < f ≤ 62	299	0.16	Instantaneous Trip
61.6 < f ≤ 61.7	299	0.16	30
60.6 < f ≤ 61.6	299	0.16	180
60.5 < f < 60.6	299	Continuous	Continuous
59.4 < f < 60.5	Indefinite	Continuous	Continuous
58.8 < f ≤ 59.4	Indefinite	Continuous	Continuous
58.4 < f ≤ 58.8	299	180	180
57.8 < f ≤ 58.4	299	180	30
57.3 < f ≤ 57.8	299	180	7.5
57.0 < f ≤ 57.3	299	180	0.75
f < 57	Instantaneous Trip	0.16	Instantaneous Trip

[1] For voltage and frequency protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to frequency protective relays applied on the individual generating unit of the dispersed power producing resources, as well as frequency protective relays applied on equipment from the individual generating unit of the dispersed power producing resource up to the point of interconnection.

European Grid Codes [24-27]

In Europe, the existing smart inverter requirements vary greatly from one country to another. Table 4.4 and 4.5 illustrate these differences by comparing the smart inverter functions currently mandated in various countries for both the low- and medium-voltage networks.

Table 4.4. Comparison of the Grid-Support Functions Currently Required in Germany, France, Spain, and Italy for Inverter-Based Generation Connected to the LV Network [25]

LOW VOLTAGE		Germany	France	Italy	Spain	Europe ≤16A	Europe >16A
		VDE AR N 4105:2011 National Standard LV: ≤1kV	Arrêté 04/23/2008 Arrêté 02/15/2010 Ministerial decrees LV: 50V-1kV	CEI 0-21:2014 National Standard LV: ≤1kV	UNE 206007-2 IN:2014 National Standard LV: ≤1kV	EN 50438:2013* (applicable 11/2016) European Standard LV: ≤1kV	CLC/TS 50549-1:2015 (non-binding) CENELEC Specification LV: ≤1kV
Active Power Control	Remote ON/OFF	>100kW, optional		>6kW			all
	Remote control of P	>100kW		>6kW	>100kW		all
	P(f) at overfrequency	all	>5MW	all	>100kW for mainland	all	all
	Minimum capability to uphold P in-feed with falling frequency					all	all
	P(f) at underfrequency						
	P(U)					optional	optional
Reactive Power Control	cos φ fix	all		>3kW	all	all	all
	cos φ (P)	>3.68kVA		>3kW		all	all
	cos φ (V)						all
	Q fix				all		all
	Q (V)	optional		>6kW	>100kW	all	all
	Q (P)						all
Grid Fault Response	LVRT			>6kW	all		all
	HVRT						all
	LFRT‡	47.5Hz	47.0Hz, >5MW	47.5Hz	47.5Hz	47.5Hz	47.5Hz
	HFRT‡	51.5Hz	52.0Hz, >5MW	51.5Hz	51.5Hz	51.5Hz	51.5Hz
	Reactive current support						

Table 4.5. Comparison of the Grid-Support Functions Currently Required in Germany, France, Spain, and Italy for Inverter-Based Generation Connected to the MV Network [25]

MEDIUM VOLTAGE		Germany	France	Italy	Spain	Europe
		BDEW MV Guideline (2008, 2013) Industry guideline MV: 1kV-60kV	Arrêté 04/23/2008 Arrêté 02/15/2010 Ministerial decrees MV: 1kV-50kV	CEI 0-16:2014 National Standard MV: 1kV-150kV	UNE 206007-2 IN:2014 National Standard MV: 1kV-36kV	CLC/TS 50549-2:2015 (non-binding)
Active Power Control	Remote ON/OFF	all		>100kW		CENELEC Specification
	Remote control of P	all		>100kW	>100kW	MV: 1kV-36kV
	P(f) at overfrequency	all	>5MW	all	>100kW for mainland	all
	Minimum capability to uphold P in-feed with falling frequency		>5MW			all
	P(f) at underfrequency					all
	P(U)					optional
Reactive Power Control	cos φ fix	all		all	all	all
	cos φ (P)	all		all		all
	cos φ (V)					all
	Q fix	all		all	all	all
	Q (V)	all		all	>100kW	all
	Q (P)					all
Grid Fault Response	LVRT	all	>5MW	all	all	all
	HVRT			all		all
	LFRT‡	47.5Hz	47.0Hz, >5MW	47.5Hz	47.5Hz	47.5Hz
	HFRT‡	51.5Hz	52.0Hz, >5MW	51.5Hz	51.5Hz	51.5Hz
	Reactive current support					all

5. DER Modeling Practices

There are different aspects of modeling for different study purposes. This report will focus on the discussions of generic models that can be used in commercial positive-sequence simulation platforms for assessing system wide DER impacts.

Many groups, such as the three listed below, are have initiated industry-wide efforts on the development of generic models for DERs.

- Western Electricity Coordinating Council (WECC) Renewable Energy Modeling Task Force [28]
- North American Electric Reliability Corporation (NERC) Load Modeling Task Force
- Electric Power Research Institute [29]

The recent NERC DER Modeling Reliability Guideline [4] provided in-depth details on how DERs can be modeled and their associated model parameters. Figure 5.1 below is an overview of how DERs are represented in a power flow and dynamic case. Please refer to [4] for full details.

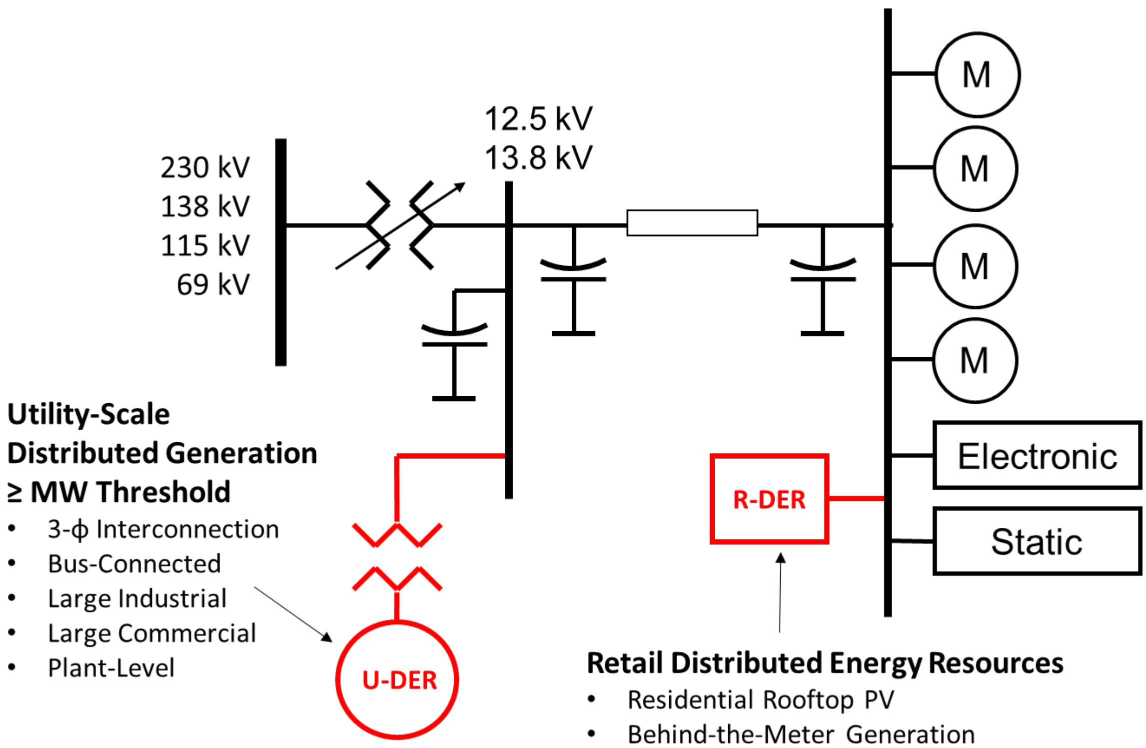


Figure 5.1. Load and DER Representation in Power Flow and Dynamics

In order to model DERs in the power flow and dynamic cases, the NERC reliability guideline [4] also provided a minimum list of information that Transmission Planners and Planning Coordinators should have related to DER:

- U-DER

- Type of generating resource (e.g., reciprocating engine, wind, solar PV, battery energy storage)
- Distribution bus nominal voltage where the U-DER is connected
- Feeder characteristics for connecting U-DER to distribution bus, if applicable
- Capacity of each U-DER resource (Pmax, Qmax)
- Control modes – voltage control, frequency response, active-reactive power priority

- R-DER
    - Aggregate capacity (Pmax, Qmax) of R-DER for each feeder or load as represented in the power flow base case
    - Vintage of IEEE 1547 (e.g., 2003) or other relevant interconnection standard requirements that specify DER performance of legacy and modern DERs (e.g., CA Rule 21)—legacy DER and modern DER should be represented in two DER models in order to capture the trip or ride-through characteristics during voltage or frequency excursions
    - As available, aggregate information characterizing the distribution circuits where R-DER are connected

In addition to the data as mentioned above [4], PV shape data and DER forecast are also important for transmission planners to study the DER impacts.

On certain utility systems, PV is the dominating DER type. To properly model PV capacity in the case, both nameplate capacity and PV shape data are necessary. PV shape data is critical to properly select output level for solar PV for various scenarios studied in planning assessment that represent different seasons and different times of the day. As an example, the graphs below indicate that only about 40% PV aggregate nameplate capacity value should be modeled for a scenario that represents a snap shot case for the hour of gross summer peak load peak, see figure 5.2. Whereas, no output should be modeled for a scenario that represents the hour of gross winter peak load, see figure 5.3.

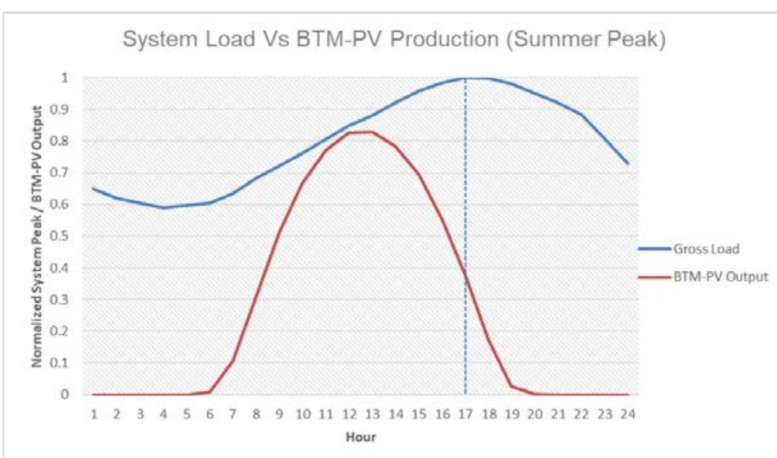


Figure 5.2. Example of Solar PV Output Level at Hour of Gross System Summer Peak Load

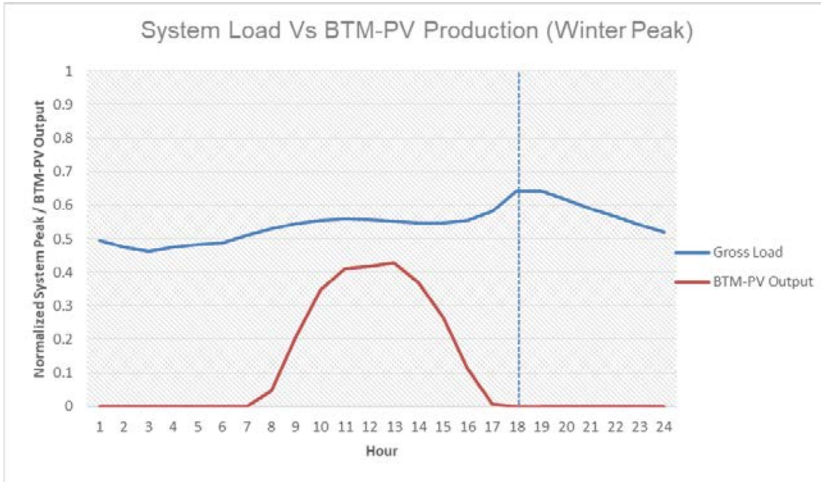


Figure 5.3. Example of Solar PV Output Level at Hour of Gross System Winter Peak Load

While the above examples can be instructive, the loading characteristics of each system may be unique. Additional analysis should be done to understand the relative coincidence of typical solar output compared to system loading.

In order to predict the DER impact for future study years, DER forecast information is also required. It is important to forecast DER separately from the demand. It is also important to estimate the DER vintage for each year considering the inverter lifetime so the aggregated DER dynamics can be properly represented by a combination of legacy inverters and modern inverters with separate DER models of different tripping and ride-through characteristics. This information may be readily available from the distribution inventory. If not, field surveys and/or estimations can be utilized.

The DER Subgroup of the NERC Essential Reliability Services Working Group has published a technical brief document on data collection recommendations for DERs [30]. The document presents results of evaluation of the data that needs to be collected and shared and makes recommendations for ongoing activities.

6. DER Study Scenarios

This section discusses the potential scenarios that can be considered for planning studies to assess DER impacts on the transmission system.

6.1 Consideration of Solar Variability

This discussion focuses primarily on photovoltaic (PV) generation. The output of PV plants varies throughout the day and is dependent on four main factors:

- Position of the sun as it rises and sets
- Variances in clouds and weather
- The compass direction the panels face
- Whether the panels have no tracking, single-axis tracking, or two-axis tracking

Even though PVs are sometimes co-located with customer load sites, their output varies independently from customer load, thus adding a new dimension to possible system conditions requiring analysis.

The transmission planning process focuses on the most extreme operating conditions. Traditionally, these have included scenarios such as summer peak load, winter peak load, light load, and, possibly, high-transfer scenarios.

The new variable of PV generation needs to be incorporated into transmission planning processes in regions with a significant penetration of PV sites. One method is to make assumptions about PV output in traditional planning scenarios then create additional scenarios to address other potentially severe conditions resulting from PV generation variability. For example, in addition to the peak summer case where load is at highest, a summer shoulder case or a spring shoulder case where PV is at the highest should be studied.

Another way to determine extreme scenarios considering both DER output and customer load is the concept of net transmission load (NTL). At any given moment, the output of DERs subtract against the gross customer load resulting in a net load seen by the transmission system at each substation. NTL on a substation may go negative when DERs are high and customer load is low. Tracking actual NTL by substation or totals by region can help to determine appropriate high- or low-DER scenarios for planning studies. For instance, the highest NTL may occur in the summer when the sun has set but the customer load is somewhat high. Another example is just before the sun rises or after it sets in winter and customer load is high.

Similarly, it is important to understand that minimum transmission load may not necessarily occur when gross customer load is lowest. It could occur during times when DER output is high and customer load is only moderately low. Tracking and analyzing actual NTL levels may help utilities identify severe, yet realistic, scenarios that should be included in transmission analysis. Other unforeseen conditions may be revealed as well.

Additionally, due to the rapid increase and decrease in solar production due to rising and setting sun, it may be insightful to study a scenario one or two hour advanced or delayed from the peak loading conditions. Depending on the loading characteristics of the system, it may be that the loading is 98% of peak one hour prior (e.g., at 4 pm when solar is ~50% output) and 98% of peak one hour after (e.g., at 6 pm when solar is ~10%

output). These drastic changes in solar production can yield very different results and would be useful sensitivities to study.

Table 6.1 below shows an example from one of the largest utilities in the Eastern Interconnection. The traditional summer peak case uses an assumption for solar generation output (35% in this example). Each utility or region will need to determine an appropriate solar generation level applicable to their system. Actual measured total PV output is preferred, but assumptions can be made if no metered data is available.

Table 6.1 also shows an assumption of zero PV output during winter peak conditions. For most regions, winter peak load typically occurs just before or near sunrise. However, this value should be decided based on the needs of each planning region. Similarly, the example in table 6.1 shows zero PV output during light load conditions, which generally occur during the late night or early morning hours.

Notice, however, that the first three traditional planning scenarios do not consider times when PV generation is at a high level. High PV output scenarios need to be considered.

Table 6.1. Hypothetical Transmission Planning Scenarios including Solar Variability

Scenario	System Load (% of Peak)	Solar Generation (% of rated)
Base Cases		
Summer Peak (5 pm)	100%	35%
Winter Peak (7 am)	100%	0%
Light Load (Spring Sunday 4 am)	35%	0%
Sensitivity Cases		
Summer Shoulder (1 pm peak day)	90%	100%
Summer Shoulder (8pm peak day)	90%	0%
Light Load (Spring Sunday noon)	40%	100%

In table 6.1, a summer shoulder case is listed for a time (e.g., 1 pm) during the summer peak day when PV generation is expected to be at its maximum. While total PV generation in a region may never truly reach 100% of the total rated output of all plants, 100% may be an appropriate conservative assumption for transmission planning purposes.

Another summer shoulder case is shown representing the time around sunset (e.g., 8 pm) when PV generation is gone but customer load is still high. Each planning region should decide appropriate customer load levels for shoulder cases.

The last example shown in table 6.1 is an extreme light load case that may occur on a mild spring day with low customer load and maximum PV output. High PV output, both DER and transmission-connected, may result in high voltages and unexpected flows on the transmission system.

Table 6.2 provides an example of scenarios considered in a recent study on one system in the Western Interconnection.

Table 6.2. Example of Study Scenarios, Load Levels and Rooftop Solar PV DG Output

Scenario	Load (% of peak)	Solar PV DG Output (% of installed)
Summer peak load conditions. Peak load time – hours between 16:00 and 18:00	100%	33%
Winter peak load conditions. Peak load time – hour between 16:00 and 18:00	95%	0%
Spring light load conditions. Light load time – hours between 02:00 and 04:00	54%	0%
Spring off-peak load conditions. Off-peak load time – weekend morning	65%	94%
Summer peak load conditions with peak-shift sensitivity	100%	9%

The first four scenarios listed in the table 6.2 are traditional baseline transmission planning scenarios. They include different load levels where output from the rooftop PV varies from 0% to almost 100% of rated, depending upon the season and time of the day the scenario represents.

The fifth scenario in table 6.2 is a sensitivity scenario that represents the hour of the net peak (gross PV). Currently, the demand forecast used in the transmission planning process is for a single hour based on the historical gross peak load hour. With the potential for significant growth in PV installations in future, the areas with high PV penetration could have lower net load during the traditional gross load peak hour and have relatively higher net load in the late afternoon (i.e., shifted peak hour) due to lower output from PV.

Once base scenarios are developed, steady-state and dynamic analysis should be performed to determine the impacts of solar generation. In dynamic analysis where DERs are included as part of the composite load model (CMLD) or are explicitly modelled, the interaction between dynamic load and PV should be closely inspected. In sensitivity scenarios where PV is much higher than traditional planning cases, such as the traditional summer shoulder case where PV may be assumed to be 100%, load response may be significantly impacted as a result of the increased PV.

When steady-state or dynamic issues are found in high PV scenarios, PV curtailments may be considered as solutions if applicable regional markets, regulations, and/or contracts allow it.

6.2 Consideration of Wind Generation

To date, there is very little wind generation on distribution systems. However, the variability of transmission-connected wind generation is another consideration that should be incorporated in transmission planning processes. For regions with high penetration of wind generation, this becomes yet another independent variable to consider in combination with variability of other DERs. Figure 6.1 and figure 6.2 show the output of

T&D-connected wind generation vs. system load on one system for both a summer day (figure 6.1) and a winter day (figure 6.2).

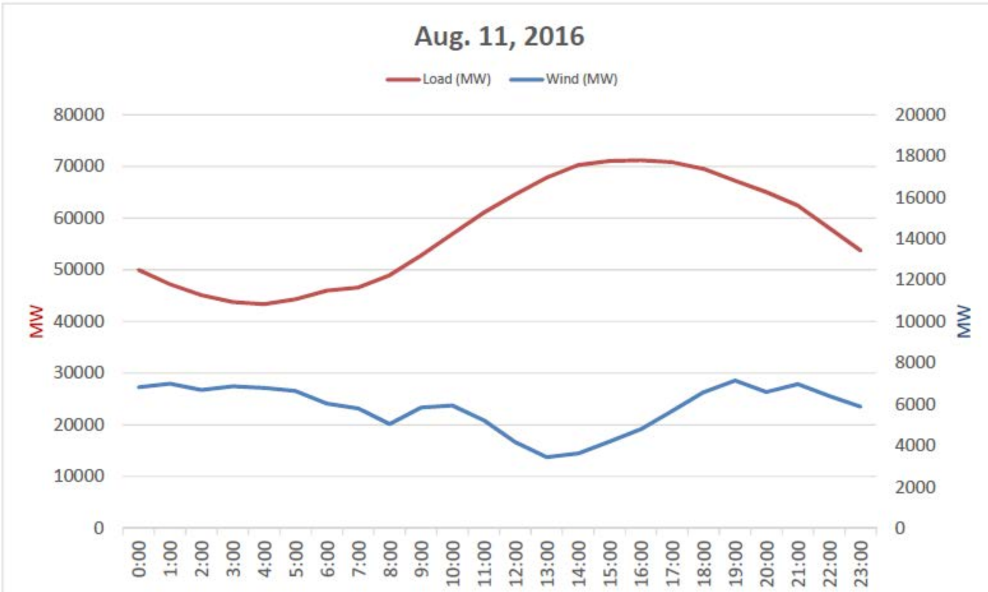


Figure 6.1. Wind Generation vs. System Load of a Summer Day

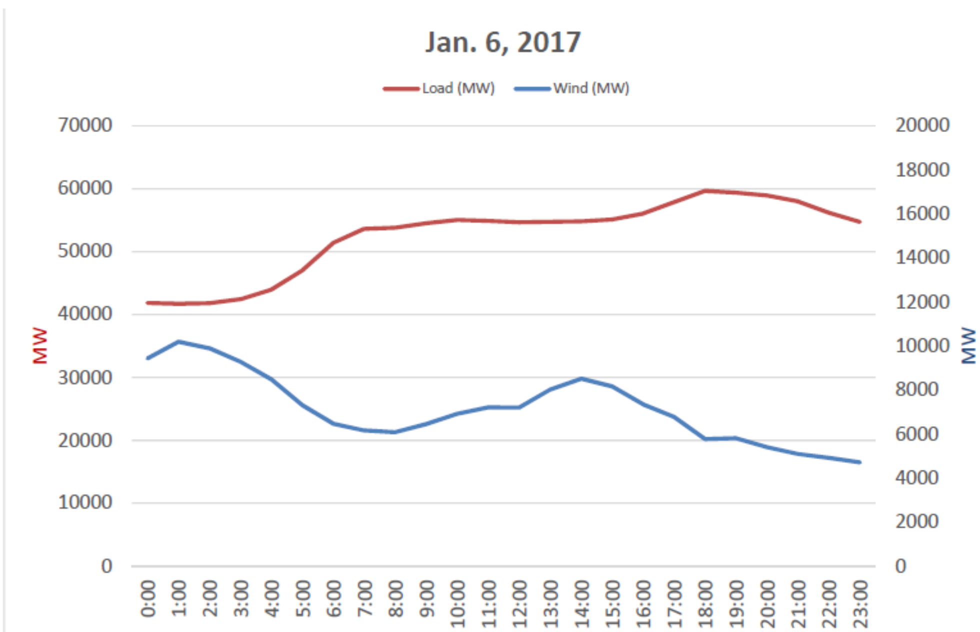


Figure 6.2. Wind Generation vs. System Load of a Winter Day

There are two primary methods to develop wind generation values for traditional transmission planning cases: averaged meter data and estimates.

One methodology to determine wind generation outputs using meter data is to average the hourly wind plant output for the past three years according to table 6.3.

Table 6.3. Sample Methodology to Determine Wind Plant Output using Averaged Meter Data

Scenario	Calculated Average Output Time Range	
	Start Time	Stop Time
Spring Peak, Summer Peak, Summer Shoulder, and Fall Peak	3 pm	7 pm
Light Load and Winter Peak	12 am	6 am

An example of applying the averaged meter data methodology is outlined in table 6.4. Here, metered data from the light-load day of the past three years is placed in a table. To determine the estimated output of this unit for light-load cases, the average value is calculated between the hours of 12:00 am and 6:00 am for each day. The average of averages is then computed to determine that the plant output should be set to 71.1 MW, or 47.4 % of maximum output, in light-load planning cases. This output value should be calculated for all wind facilities where metered data is available. The value will likely vary from plant to plant.

Table 6.4. Sample Wind Plant Output Estimation using Averaged Meter Data Methodology

Light Load Hourly Max Wind MW - 150 MW Plant				
Time	4/15/2017	5/3/2016	4/28/2015	Average
0:00	70	85	10	55.0
1:00	75	84	40	66.3
2:00	79	85	60	74.7
3:00	80	80	80	80.0
4:00	82	79	85	82.0
5:00	60	80	90	76.7
6:00	25	80	90	63.3
Average	67.3	81.9	65.0	71.1

In certain situations, metered data may not available. In these cases, it is appropriate to use estimated values. Estimated values will depend heavily on the region and should be carefully considered based upon the individual utilities needs and available data. For example, the estimates shown in table 6.5 may be appropriate for some utilities in the midwestern states of the US:

Table 6.5. Sample Estimated Wind Plant Ouput Values for Some Midwestern States of USA

Case	Estimated % of Maximum MW Output
Spring Peak	45.0%
Light Load	50.0%
Summer (Peak and Shoulder)	30.0%
Fall Peak	50.0%
Winter Peak	40.0%

7. Examples of DER Modeling and Studies

There have been many recent efforts in the area of DER modeling and studies [31-38]. This section will provide examples from recent studies performed on two California systems.

7.1 System A Study

Example: DER modeling practice in transmission planning studies [31]

Various activities in distribution systems can impact net load at the T/D interface. These include resources connected to distribution system or demand side load-modifying programs. On the demand side, these resources or programs include energy efficiency, load-modifying demand response (DR), and behind-the-meter DG (BTMDG) (PV and non-PV). On the supply side, these include utility connected DG (PV or non-PV), energy storage, and event-based DR programs.

Data source: Existing and forecasted amounts of DERs are obtained from information provided by California Energy Commission (CEC), California Public Utility Commission (CPUC), and participating Transmission Owners (PTOs). CEC's energy demand forecast report includes baseline forecast with load modifiers and corresponding self-gen peak impacts. The amount of self-gen PV (BTMDG-PV) is extracted using this information and added back to the peak demand forecast and are modeled as discrete element in power flow database. CEC also provides information about additional achievable energy efficiency (AAEE) separately, which is modeled as negative load in the power flow database. Mandated and currently procured amount of energy storage information is obtained from the "Assumptions and Scenario for Long-Term Planning" document provided by the CPUC. DR programs and supply-side connected DG information are provided by PTOs.

Modeling in study database: Current practice of modeling DER in the study database includes committed energy efficiency and load-modifying type DR embedded in demand forecast. Utility (supply side) DG, BTMDG-PV, event-based DR, AAEE, and energy storage are modeled as discrete elements in power flow database. AAEE and DR are modeled as negative load at the T/D interface. Supply side DG and energy storage are modeled as individual generators at the T/D interface and BTMDG-PV is modeled as an aggregated generator at the T/D interface.

BTMDG-PV modeling: BTMDG-PV is the dominating DER type. In the 2017-2018 Transmission Planning Process, System A used composite load model with DG to model BTMDG-PV in the study database. Identifying locations to model BTMDG-PV is also equally important. System A , in coordination with its PTOs, used information about locations of existing BTMDG-PV and information from PTOs distribution resource plans about future development forecast in coming up with locations to model BTMDG-PV. For steady-state modeling, BTMDG-PV at each bus is modeled by specifying P and Q values of PV as separate entries in power flow load data including following values:

- Pdg – MW output of distributed generation
- Qdg – Mvar of distributed generation
- Stdg – DG status

For dynamic modeling, model CMPLDWG is used to represent BTMDG-PV with following default voltage and frequency trip points:

- Voltage below which all DG is tripped – 0.5 pu
- Voltage below which DG starts to be tripped – 0.7 pu
- Voltage above which all DG is tripped – 1.1 pu
- Voltage above which DG starts to be tripped – 1.2 pu
- Fraction of DG that restarts when voltage recovers – 0.5
- Frequency below which all DG is tripped – 58.0 Hz
- Frequency below which DG starts to be tripped – 59.0 Hz
- Frequency above which all DG is tripped – 61.0 Hz
- Frequency above which DG starts to be tripped – 62.0 Hz
- Fraction of DG that restarts when frequency recovers – 0.0

Example: DER Modeling and Dynamic Studies [32]

The graph below shows the comparison of where DER is represented as part of composite load model versus where DER is netted. With the same pre-fault net load, the dynamic response and the settling final load are different, which clearly showed the need for modeling DER explicitly instead of load netting.

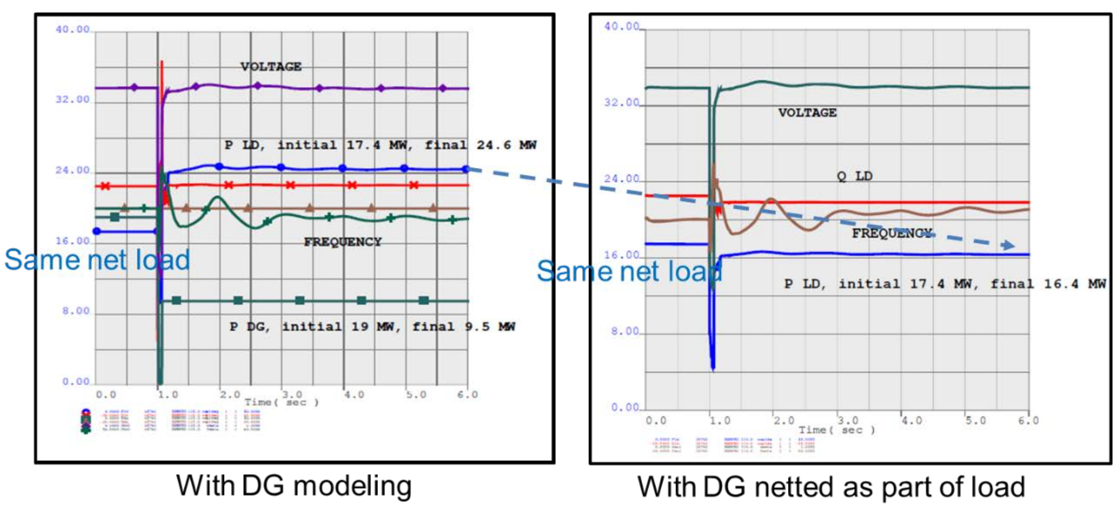
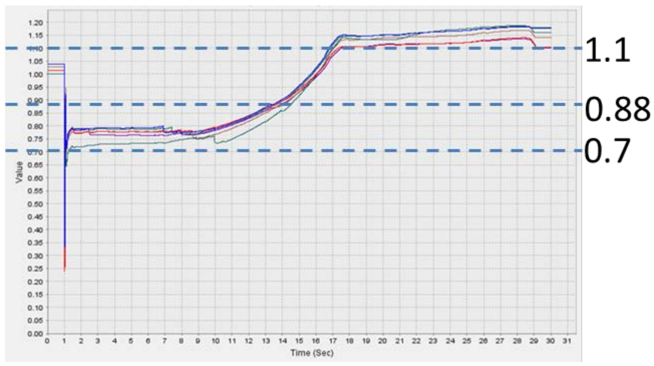


Figure 7.1. System A DER Modeling Example: with and without DER Explicit Representation

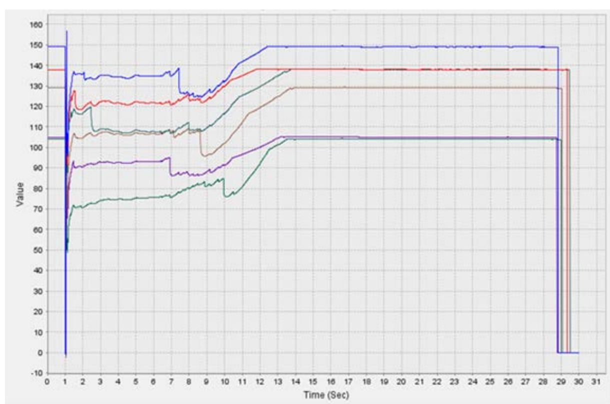
7.2 System B Study

System B performed a DER impact assessment and various sensitivity studies around composite load model parameters and smart inverter settings [33].

Figure 7.2 shows the bus voltages and active power from DERs from one simulation run. The study confirmed that DERs that do not have ride-through capability will trip during low voltage recovery, and DERs with the new California Rule 21 setting that have ride through capability will ride through the fault. The study also showed that DERs can potentially trip on high voltage even with the new rule 21 setting with ride-through capability. This is primarily due to the loss of air conditioner load, which results a high settling overvoltage post-fault recovery. This potential tripping on high voltage is dependent on the air conditioner stalling threshold. When the air conditioner stalling threshold is high, more air conditioning is prone to stalling and thermal tripping, which results in a high post-fault recovery voltage and potential DER tripping on high voltage.



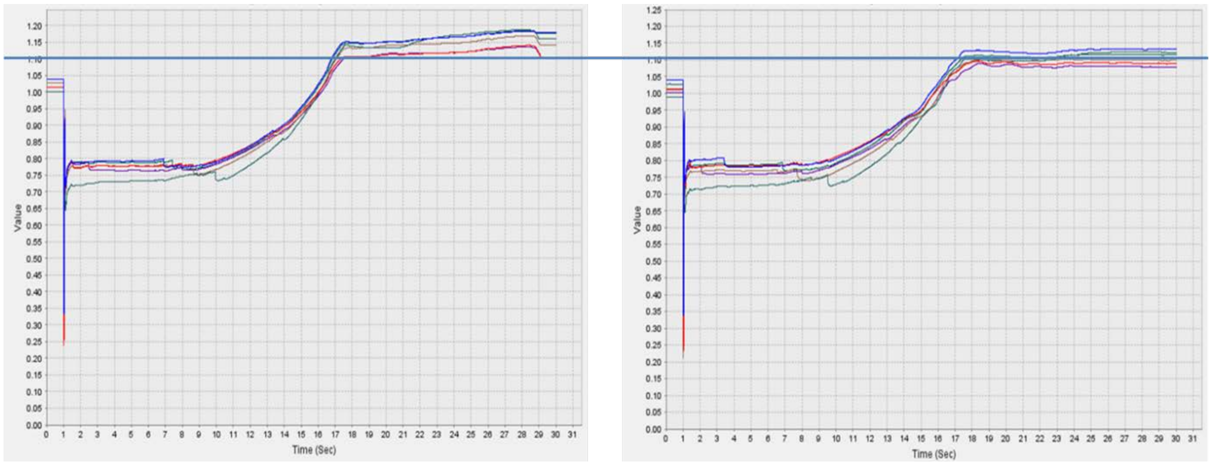
(a) Selected Bulk Power Bus Voltage



(b) Active Power from DER

Figure 7.2. System B DER Modeling and Study Example: DER Ride-Through Setting

The study showed that enabling DER voltage control would improve system voltage performance, as can be seen from the figure below.



(a) DERs are all on Active Power Control (b) Half DERs are on Voltage Control

Figure 7.3. System B DER Modeling and Study Example: DER Voltage Control Setting

The fault type matters. The graph showed system voltage profiles under different fault conditions as well as when the air conditioning stalling feature is disabled and enabled in the study.

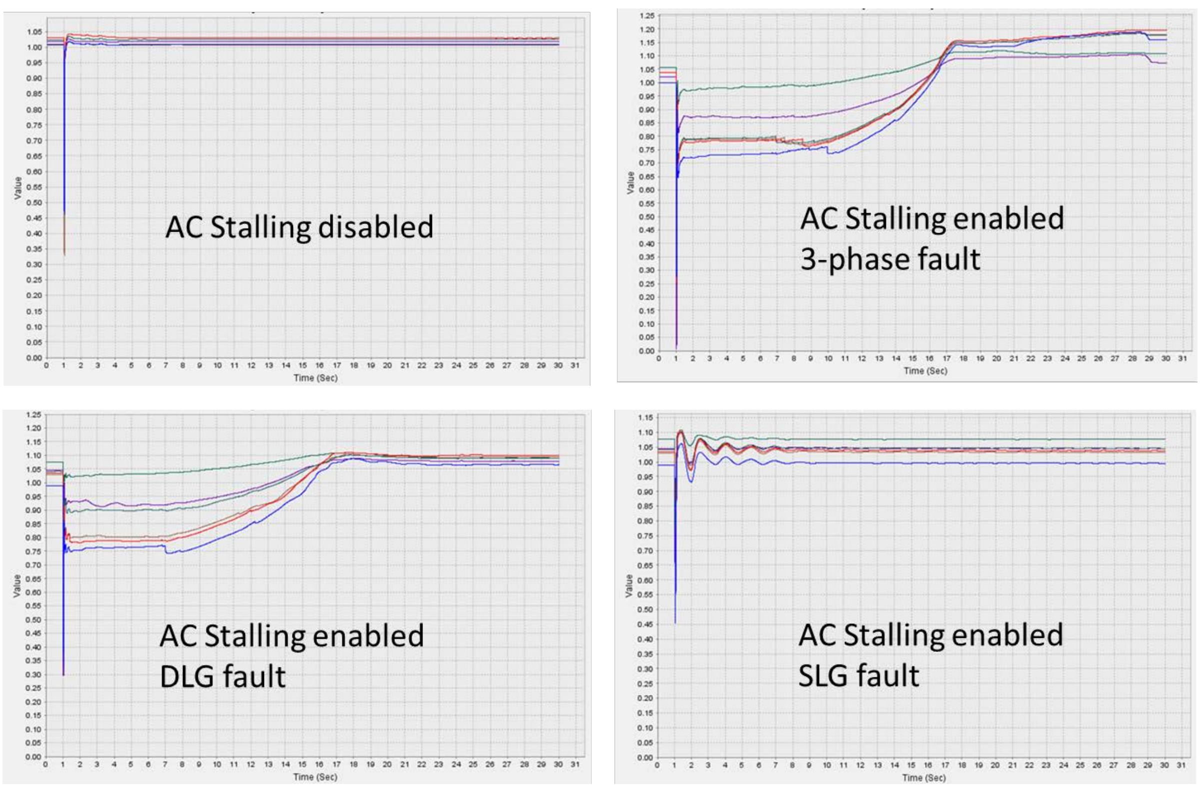


Figure 7.4. System B DER Modeling and Study Example: Fault Matters and FIDVR Impacts

8. Conclusions

The increasing penetrations of DERs is resulting in new challenges for transmission planning and operations. For areas where the DER penetration is high, the DER should no longer be netted as load modifier, but rather should be explicitly represented and studied.

This document provides details required to model DERs and study DER impact to bulk power system, which range from the DER model to be used, data required to represent DERs, to the additional study scenarios to be considered. Examples of DER modeling and experiences from several utilities are also provided.

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