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CLEAN ENERGY MINISTERIAL
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CLEAN GRID VISION:
A U.S. PERSPECTIVE

Chapter 2. Distribution Issues and Tools

Barry Mather, Jun Hao, Fei Ding, Yingchen Zhan, Michael Coddington, Ella Zhou –
National Renewable Energy Laboratory

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National Renewable Energy Laboratory
15013 Denver West Parkway
Golden, CO 80401
303-275-3000 | www.nrel.gov

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Fatih Birol	International Energy Agency
Roland Brundlinger	Austrian Institute of Technology
Leon Clarke	Pacific Northwest National Laboratory
Laura Cozzi	International Energy Agency
Paolo Frankl	International Energy Agency
Dolf Gielen	International Renewable Energy Agency
Toni Glaser	German Federal Ministry for Economic Affairs and Energy
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Hans Jorgen Koch	Nordic Energy Research
Jiang Lin	Lawrence Berkeley National Laboratory
Mark O'Malley	Energy Systems Integration Group
Lynn Price	Lawrence Berkeley National Laboratory
Martin Schope	German Federal Ministry for Economic Affairs and Energy
Charlie Smith	Energy Systems Integration Group
Ryan Wiser	Lawrence Berkeley National Laboratory

SGERI developed the counterpart report, *Clean Grid Vision—A Chinese Perspective*. The collaborative research with SGERI during the course of the program provided the authors with insights into the Chinese power system and stimulated fresh thinking on some of the common challenges in energy transition.

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Any error or omission in the report is the sole responsibility of the authors.

List of Acronyms

AGC	automatic generation control
BESS	battery energy storage system
DER	distributed energy resource
DEW	Distributed Energy Workstation
DOE	U.S. Department of Energy
EPRI	Electric Power Research Institute
EPS	electric power system
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
GHC	grid-hosting capacity
GIS	geographic information system
HELICS	Hierarchical Engine for Large-scale Infrastructure Co-Simulation
IGMS	Integrated Grid Modeling System
ISO	independent system operator
NREL	National Renewable Energy Laboratory
PV	photovoltaic
QSTS	quasi-static time series
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
UFLS	under-frequency load shedding
UL	Underwriters Laboratory
VAR	volt-amp reactive
VRE	variable renewable energy
WECC	Western Electricity Coordinating Council

Preface

The *Clean Grid Vision—A U.S. Perspective* is a part of the National Renewable Energy Laboratory's (NREL)'s 2015–2021 Chinese Programme for a Low-Carbon Future and collaborative research with China's State Grid Energy Research Institute (SGERI). This multiyear program seeks to build capacity and assist Chinese stakeholders to articulate low carbon pathways to achieve energy systems with a high share of renewable energy, energy efficiency, and low carbon emission.

The Clean Grid Vision comprises two major reports: *Clean Grid Vision—A U.S. Perspective*, written by NREL, and *Clean Grid Vision—A Chinese Perspective*, written by SGERI. The former summarizes NREL's lessons learned on some of the main issues in power system transition:

- Power system planning and operational analysis are discussed in Chapter 1, "Clean Grid Scenarios."
- Renewable grid integration challenges and modeling tools at the distribution network level are discussed in Chapter 2, "Distribution Issues and Tools."
- Grid reliability and stability challenges and the technologies to address them at the transmission-network level are discussed in Chapter 3, "Grid-Supporting Technologies."
- Recent dynamics in electricity demand such as energy efficiency, demand response, and electrification are discussed in Chapter 4, "Demand-Side Developments."
- Emerging issues in power market design and market evolution related to the increasing penetration of renewable energy are discussed in Chapter 5, "Power Market Trends."

The scope of *Clean Grid Vision—A U.S. Perspective* is limited to summarizing the main lessons learned and best practices through NREL's power system research in the past 6 years, with a focus on the U.S. power system. It can be compared to and contrasted with SGERI's report that focuses on China's power system.

As a summary report, most of the works cited here were conducted during 2015–2020. While some of the assumptions for these studies, especially the ones related to renewable energy and battery technology costs, are outdated, the main conclusions remain salient and offer valuable insights for planning and operating power systems and power markets with high levels of renewable energy.

More information on the Clean Grid Vision is available at www.nrel.gov/international/clean-grid-vision.html.

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Chapter 2: Distribution Issues and Tools

Highlights

- Interconnecting distributed energy resources (DERs) to the distribution network raises many technical challenges, including impacts related to voltage, protection coordination, power quality, and reliability at both distribution and transmission levels.

- A range of distribution-level study tools and methods have been developed to understand and manage such impacts. These include tools such as PRECISE, which uses advanced optimization of inverter settings to help utilities improve system performance. Those inverter settings can then be used in quasi-static time series simulation for large-scale DER integration planning and operational decision-making.

- Integrated transmission and distribution tools (e.g., the National Renewable Energy Laboratory's [NREL's] Integrated Grid Modeling System) are also developed to enable full-scale transmission and distribution modeling that helps the understanding of millions of DERs' impacts on the transmission grid and identifying the scalability of DER integration solution for interconnected power systems.

This chapter focuses on the specific renewable grid integration challenges associated with increased levels of solar and wind generation and the modeling tools that help address these challenges. With the ever-higher levels of DERs being integrated onto the distribution system, an increasing number of distribution system issues, and even bulk system issues, are becoming more common. The mitigation of these issues for new DER interconnection requests is then of greater concern to utilities experiencing localized high penetrations of DER, an overall high level of DERs, or an expectation of high levels of DERs within their distribution system planning horizon. To examine the mitigation options, the set of commonly used distribution system analysis tools continues to be developed and improved. As the aggregate amount of DERs reaches considerable levels for, at least, some hours of the year, additional toolsets are being employed to both investigate and mitigate the bulk system-level impacts of DERs via transmission-distribution co-simulation.

2.1 Introduction to Grid Issues

With the increased levels of renewable energy resources being integrated at both the distribution and transmission system levels, multiple grid-related challenges have been identified, researched, and mitigated to varying degrees. A comprehensive view of distribution grid impacts is provided first, followed by a look at the transmission-level issues stemming from high levels of DERs.

2.1.1 Overview of Impacts to the Distribution Grid

The nature of DERs is that they are distributed along locations on distribution feeders and lateral lines, with some DERs tied through transformers directly to the distribution systems and other DERs tied onto the secondary conductors behind transformers. Some DERs are single-phase, and some are two- or three-phase, and many of these DER systems export power and energy to the distribution system itself while some of the power and energy is consumed at or near the DER installation.

The earliest DER systems were primarily of small wind generators and then inverter-based PV generators. Most early DER systems were measured in kW and were often so small that all power and energy produced was consumed locally—little or no exporting from the DER site. But as the growth of DERs increased exponentially during the 2010s, DER increasingly became a great concern for utility engineers and operations departments, and, in fact, DERs often exported large amounts of power and energy on thousands of distribution feeders throughout North America (and similar stories can be found in other countries).

The early days of DER tied to the grid were mostly focused on the impacts near the point of interconnection or point of common coupling, but have quickly evolved where utility engineers and operators now are concerned about DER impacts on the secondary side of many distribution transformers, on the primary feeder lines themselves, at substations, and now on the bulk power system. Millions of small DERs (measured in kWs) and larger DERs (measured in MWs) have now become ubiquitous on the distribution grid, and their potential impacts cannot be ignored.

This section is focused on the concerns and impacts of DERs on the distribution system location on the larger grid, the section that has traditionally been designed to reduce voltage levels to serve customer electricity needs. The goal of an electrical utility engineer or DER technician is to ensure the proper interconnection of DERs and to evaluate and perhaps study, using complex computer models, the potential impacts of the DER and to ensure no problems arise.

2.1.2 Distribution System Impacts From DERs

DERs have become ubiquitous in many distribution systems throughout North America and across most continents. These large numbers of DERs have begun to impact the distribution systems first at the point of common coupling (usually the electric meter) and then with greater levels of capacity penetration, upon the distribution feeder overall. These impacts are monitored and controlled carefully so that the potentially negative impacts from DERs are not realized. Experience, as well as sophisticated distribution system models, have informed utility engineers and operators of the potential impacts that should be anticipated.

Before a DER system connects to the distribution system, it must first be reviewed by the electric utility operating that distribution system. It has been documented that many small DERs, such as small rooftop solar photovoltaics (PV), are not high on the concern list for utility engineers and other interconnection experts, but larger PV systems and those miles from the distribution substation are much more likely to have negative impacts such as voltage range violations and protection coordination challenges [22]. This section of the paper will focus on many of the types of concerns and potential violations that may occur if the interconnection[1] is not properly employed.

2.1.3 Major Topics of Focus for Distribution Engineers and Operators

Traditional areas of focus for distribution system operators are safety, reliability (and power quality), and cost. These continue to be top-tier subjects of focus for all electric utilities, even with the significant amount of change being experienced on distribution systems.

- Safety: The safety of the public and the electric utility workers must remain the most important topic of focus for electric utilities, as electricity is dangerous and can become deadly if not treated properly.
- Reliability: Keeping the power available and minimizing the average duration of power outages (typically measured by the System Average Interruption Duration Index [SAIDI][2]) and the frequency of outages (typically measured by the System Average Interruption Frequency Index [SAIFI]) is an

[1] Interconnection is a process of reviewing, studying, and typically approving a DER tie to the distribution system. This is generally a utility process, often under state laws, and the customer or DER developer. See https://www.nrel.gov/docs/fy19osti/72102.pdf for more details.

[2] SAIDI is defined in the standard IEEE 1366, along with other reliability metrics such as SAIFI, the Customer Average Interruption Duration Index, and so on. Read more at https://www.eia.gov/todayinenergy/detail.php?id=37652.

extremely important aspect of operating an electric distribution system. Included in reliability is overall power quality, which is ensuring the voltage and frequency of the electricity is maintained within national standards requirements.

- Cost: Delivering safe and reliable power at the lowest cost continues to be a prime mission for electric distribution utilities. And moving into the new phase of DER interconnection will still require that utilities design, build, and operate their systems in the most cost-effective manner possible.

The engineers, operators, and many support staff that work to build and maintain distribution systems will continue to focus on safety, reliability, and cost, but are shifting their focus in many places to support the deployment of DERs. This significant shift in deploying distributed generation has complicated the landscape for electric utilities, making education and training more important for all stakeholders.

2.1.4 Technical Concerns When Evaluating Interconnection of DERs to the Distribution System

Interconnecting new loads and new sources of generation (DERs) create various concerns for electric utility engineers and the operations departments who maintain those distribution circuits 24/7. These technical concerns must be recognized, possibly modeled and studied, and sometimes mitigation strategies must be deployed. Most utilities utilize a method similar to Figure 2- 1. Once the utility receives an application for interconnection, they generally take the following steps:

1. Check for accuracy of the application, including the location, customer electrical data, type of rate or tariff, and reject the application if there are errors or omissions.
2. If grid's hosting capacity maps and/or data are available for that location, compare application DER size and technology type against the hosting capacity maximum for that site [1].

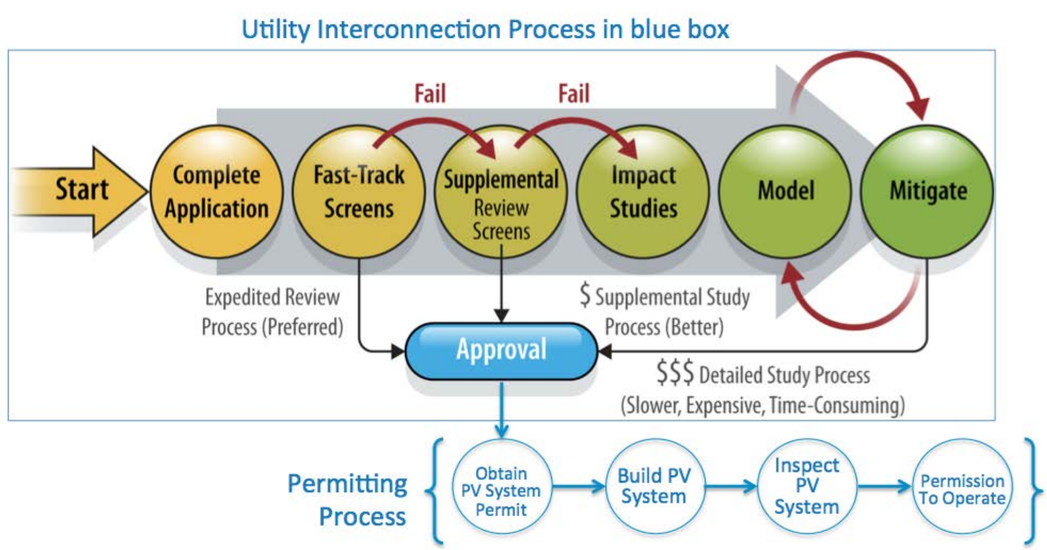


Figure 2- 1. Typical utility interconnection process that includes technical review options of fast-track screens, supplemental screens, and detailed impact studies

Source: [1]

3. Apply fast-track technical screens for any violations. A violation may trigger a supplemental study or a detailed impact study. Application may be approved if the fast-track screens are not violated.

4. Apply supplemental review screens if available. The Federal Energy Regulatory Commission (FERC) Small Generator Interconnection Process (SGIP) added this step,[3] but the details behind these screens may vary significantly between states and utilities. Application may be approved if the supplemental review screens are not violated.
5. If fast-track screens or supplemental review screens are violated, or other system details require, a detailed impact study may be completed by the utility (or an engineering firm hired by the utility). These studies will incorporate the use of sophisticated modeling software packages, and those utilize electrical models of the distribution system being evaluated. There may be one or several types of studies to evaluate the proposed system, and those are covered later in this chapter. Application may be approved if the detailed impact study does not indicate any possible problems that would occur because of the DER system(s). This is also the point where any required mitigation strategies are developed and would need to be paid for by the applicant (there may be no actual cost associated with some mitigation strategies, such as modifications to a smart inverter).
6. Depending upon the results of the technical review (Steps 2–5 above), the utility has the option to grant approval for the DER system to be installed. And it is important to note that the design and construction of the DER is not within the jurisdiction of the electric utility but is under the jurisdiction of the local authority having jurisdiction. The authority may be the local government building department that is responsible for issuing permits, or it may be the responsibility of the state authority. Generally, a DER system would need to apply for a building permit, and the DER system would likely require inspection, as well as a final release sent to the utility notifying them of the DER installation approval.
7. The utility will issue a permission-to-operate order once the authority having jurisdiction has notified the utility. The utility may also need to install one or more electrical meters (net meter and/or production meter) so that excess energy sent to the grid is accounted for. A production meter is required in some utility areas so that all DER generation, such as PV, can be accurately monitored.

2.1.5 Technical Concerns Considered During Technical Screening or Impact Studies

There are many concerns that utility engineers and operators may have in evaluating the impact of a DER system. The goal of the utility interconnection process is to ensure that concerns do not manifest themselves as actual grid problems. The following sections highlight the major concerns that utilities consider during their review. Having concerns is always a valid perspective, but studying an interconnection application (and possibly taking mitigation steps) is the method to ensure no problems occur. It is worth noting that even sophisticated modeling systems may not identify all future potential problems, but the methods discussed in this paper (and other papers[4] focused on DER interconnection [1]) should sufficiently identify the vast majority of problems and mitigate them prior to construction of the DER systems.

2.1.5.1 Voltage-Related Impacts

PV systems and other DERs may impact distribution circuits in several ways. Voltage rise and voltage variability caused by exported power and energy and source variability (cloud variability for PV is an example) are two prominent and potentially problematic areas of concern. Fluctuating voltage levels can

[3] FERC Order 792, issued November 22, 2013, added this step. See https://www.ferc.gov/whats-new/comm-meet/2013/112113/E-1.pdf.

[4] See the following papers: https://www.nrel.gov/docs/fy19osti/72102.pdf and https://www.nrel.gov/docs/fy16osti/63114.pdf.

cause disruptions to end-use equipment as well as utility equipment, and high voltage levels may damage equipment. Figure 2- 3 is an illustration of voltage that rises with distance away from the utility distribution substation. This simple figure illustrates how voltage levels may rise as it is measured away from the substation, and also demonstrates the fact that longer distribution lines with larger amounts of DERs toward the end of the line tend to exacerbate the high voltage concern. A computer modeling platform would be expected to catch this high voltage concern and mitigate it before it became a reality.

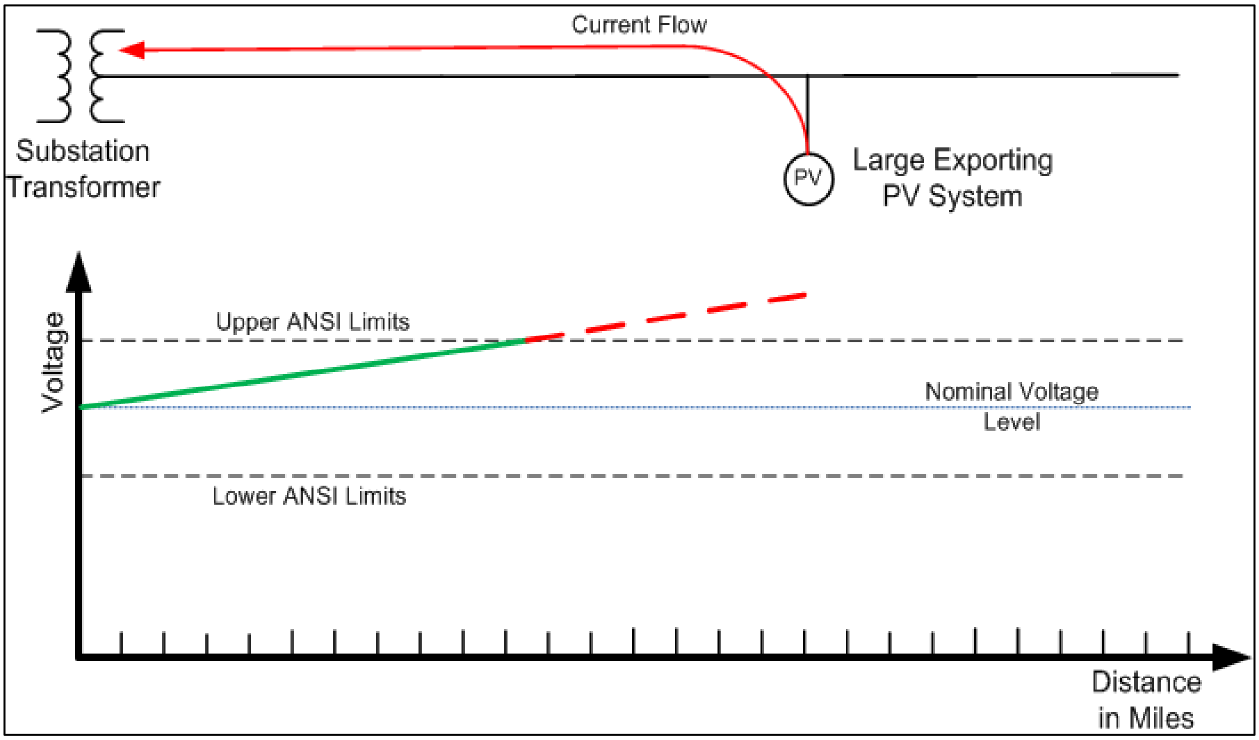


Figure 2- 2. Basic one-line diagram of a utility distribution circuit with the voltage profile shown below it

Source: [23]

The voltage level standard, ANSI C84.1, encourages utilities to maintain service voltage levels of +/- 5% of nominal voltage levels (this is the Range A shown in Figure 2- 3, commonly used by utilities outside of North America). While some utilization equipment (laptops and cell phones, for example) are designed to operate on widely different voltage levels, many devices will operate improperly or fail altogether. Maintaining a steady-state level of voltage at points of power utilization is critical so that customer (and utility) utilization equipment is not damaged.

Phase balance and voltage balance is also a concern by utility engineers and operators. Large PV and DER systems are designed to be balanced, three-phase systems that maintain current and voltage levels on each phase. But smaller DER, such as residential PV and battery systems are single-phase systems and are typically installed in a random manner and generally the phases are typically equally utilized for those DERs. There may be times when the utility distribution operators need to complete field balancing in the same manner as is done on occasion for balancing single-phase loads.

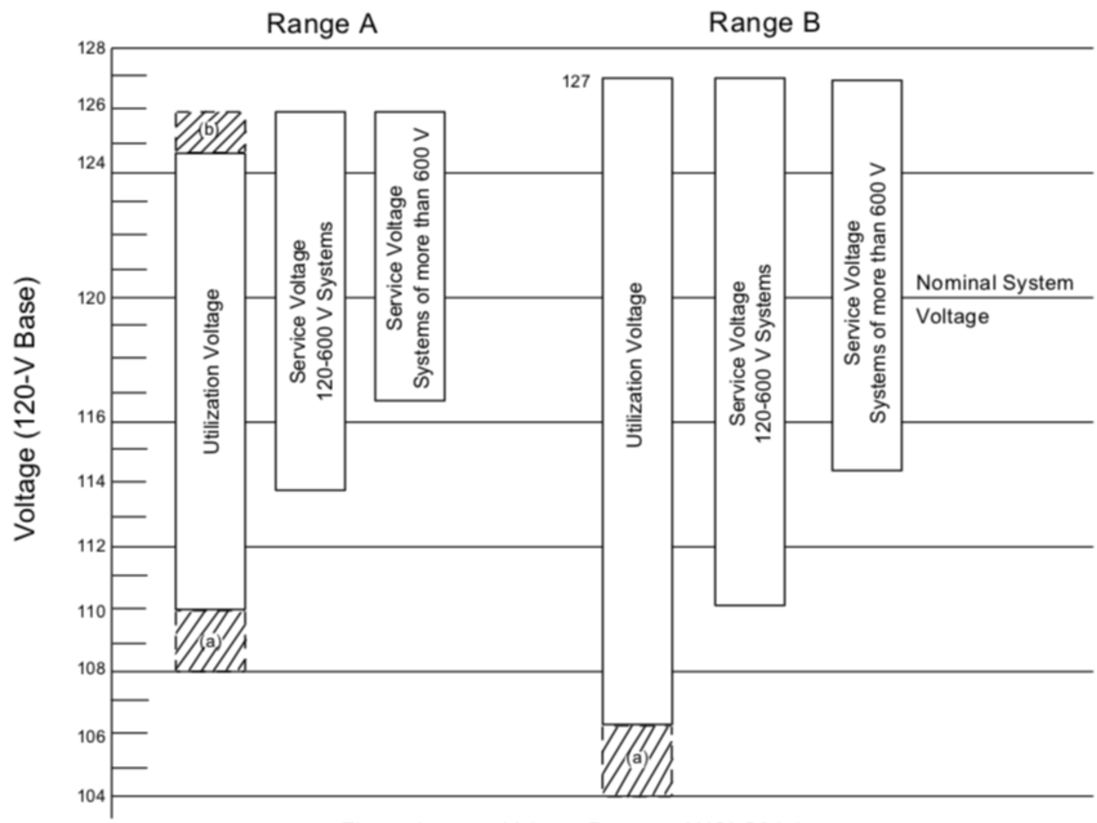


Figure 1. Voltage Ranges, ANSI C84.1

NOTES:
(a) These shaded portions of the ranges do not apply to circuits supplying lighting loads
(b) This shaded portion of the range does not apply to 120-600-volt systems.
(c) The difference between minimum service and minimum utilization voltages is intended to allow for voltage drop in the customer's wiring system. This difference is greater for service at more than 600 volts to allow for additional voltage drop in transformations between service voltage and utilization equipment.

Figure 2- 3. ANSI C84.1 ranges A and B

Source: [2]

There are many methods a utility engineer may employ to evaluate a DER interconnection application to ensure voltage levels will not be a problem. Technical screens may be a sufficient tool to evaluate voltage impacts, for example, as a very small proposed DER (a 4-kW PV system, for example) may not be a concern, as models and experience have generally dismissed very small DERs as being problem-free.

If a proposed DER is modeled and studied because of its size, location, technology type, and so on, there are always methods to mitigate the installation so that voltage violations do not occur. Mitigation strategies are discussed in the *High-Penetration PV Integration Handbook for Distribution Engineers*[5] and in other sections of this document. There are many other scientific documents that offer options for voltage problem mitigation.[6] A study in 2014 by NREL, Sandia National Laboratory, and the Electric

[5] See the report at https://www.nrel.gov/docs/fy16osti/63114.pdf.

[6] See Kacejko, Piotr, and Pijarski, Paweł. (2017). *Mitigation of voltage rise caused by intensive PV development in LV grid*.

Power Research Institute (EPRI) found that the most common concern amongst utility engineers regarding PV (and other DERs) was voltage impacts [3].

2.1.6 Protection Coordination-Related Impacts From DERs

DERs may export power and energy from their systems onto the local distribution system, adding current flow and changing the fault current calculations at every protection device on a feeder. While inverter-based DERs have very limited fault current contribution compared to the utility substation levels, they do have an impact on the flow of current during normal conditions and on fault current during abnormal conditions.

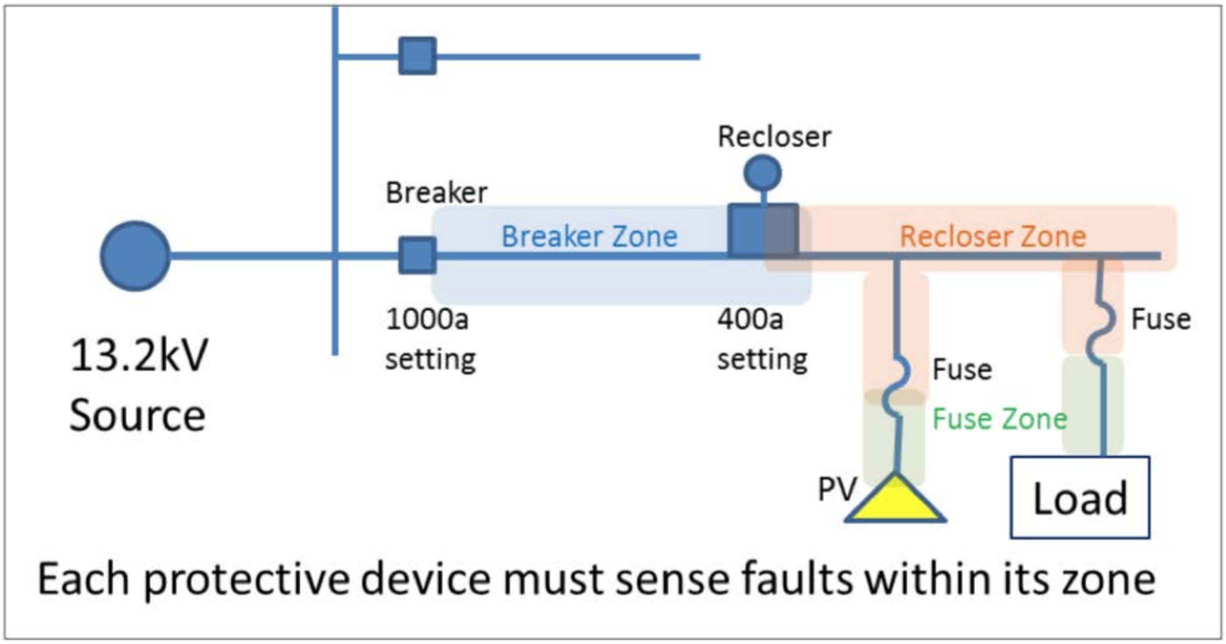


Figure 2- 4. Example of fault current from substation and from DER

The substation breaker and recloser may not remain coordinated with the fuses downstream during a fault. Source: [17]

The example in Figure 2- 4 illustrates a *breaker zone* where the normal fault current passes through the circuit breaker and the *recloser zone* where additional fault current comes from both the circuit fault current and that of the DER. Hypothetically, the load fuse may not coordinate properly with the circuit breaker or recloser if the DER adds sufficient fault current. Most inverter-based DERs provide such a low level and short duration of fault current that protection coordination may not be impacted in a practical manner. But circuit breaker relays are much more sophisticated than their older electro-mechanical predecessors and may sense fault currents far more quickly than the older relays. And so utility engineers and system protection specialists may need to consider making changes to relays as DERs are promulgated over time.

Another protection challenge is the low levels of fault current provided by power electronics and inverters. Traditional fuses require sustained fault current levels in order to clear the fuse, and typical inverters cannot provide current during a fault condition for more than a small fraction of a cycle (as shown in Figure 2- 5).

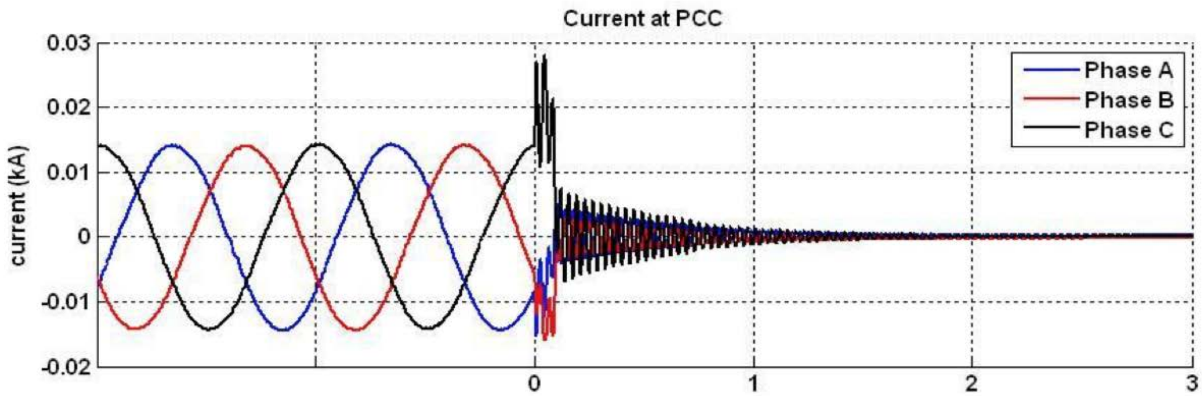


Figure 2- 5. Inverter currents during a three-phase fault close to the point of common coupling (time in cycles)

Source: [5]

There are many other system protection concerns that have been identified, and they include:

- Fault sensing
- Substation relay desensitization
- Line-to-ground utility system overvoltage
- Reclosing out of synchronism
- Unintentional islanding
- Sectionalizer miscounting
- Secondary network reverse power relay malfunctions
- Cold load pickup with or without DERs
- Faults within a PV or DER system zone
- DER isolation during upstream faults
- PV tripping due to voltage sags on adjacent feeders or lateral lines
- Distribution automation studies and reconfiguration.

The *High-Penetration PV Integration Handbook for Distribution Engineers* [17] covers these topics in greater detail and is a useful reference tool when specific concerns are raised.

Many concerns by utility engineers and operators are either in the protection coordination area or in the low-fault current impact on clearing fuses realm. Overall, protection systems were originally based on large power plants delivering large power and energy capabilities at each utility substation, and the protection coordination was from the substation circuit breaker out to the end user. But with large amounts of DERs, protection coordination is becoming more complex. Software programs such as ASPEN and Milsoft LightTable® must adapt to the new and ever-changing grid.

2.1.7 Power Quality

Power quality is a term that generally refers to voltage or current waveforms that are outside of normal service ranges. Voltage outside of ANSI C84.1 Range A or B can be problematic and is itself a subset of power quality concerns. Power outages, generally measured by utilities in terms of SAIDI[7] and SAIFI (duration of outages and frequency of outages), are also special cases of power quality problems, as voltage and frequency fall to zero during an interruption or outage.

2.1.7.1 Harmonics

Voltage and current waveforms are sinusoidal in shape based on the physical characteristics and design of rotating machine generators such as hydroelectric generators or steam turbines. DERs generally employ power electronics, usually inverters that convert DC to AC waveforms and synchronize to the power grid. The presence of other frequencies other than 60 Hz on a circuit can cause equipment to overheat, malfunction, or fail altogether.

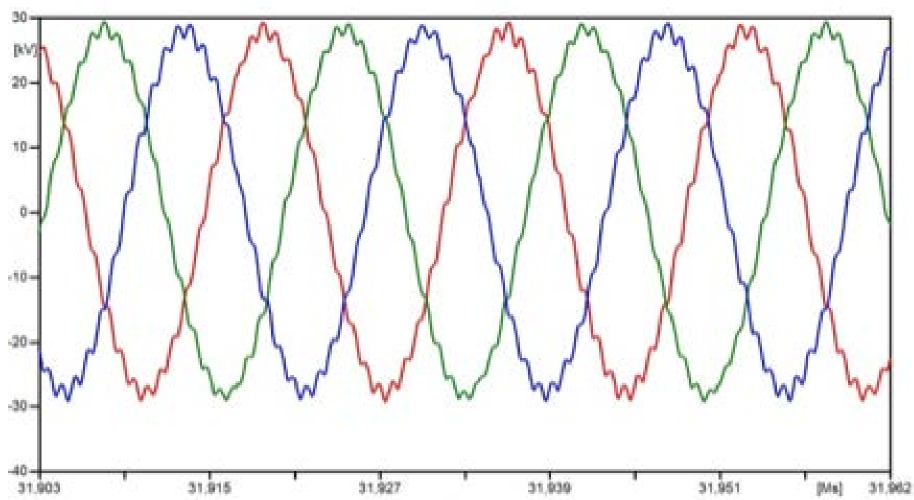


Figure 2- 6. Sinusoidal voltage waveform with harmonic content visible

Source: [6]

Both loads and DERs can contribute to the harmonic content on a power line, and while often localized in nature (on the load side of a distribution transformer) may appear on distribution feeders and even at the substation. Power quality experts have long known of the potentially detrimental nature of harmonics on power systems and tracking the source(s) of those harmonics is often challenging for utilities, electricians, and campus facility managers.

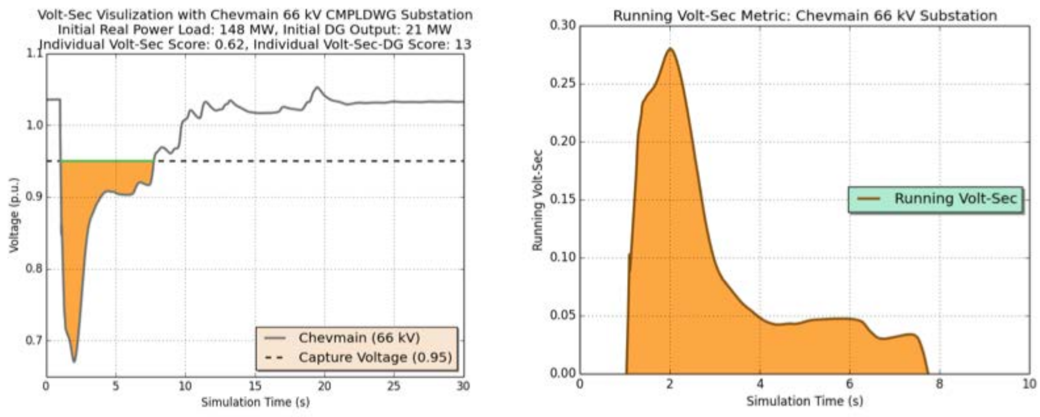
DERs must be listed under Underwriters Laboratories (UL) 1741 and operate under the IEEE 1547 requirements in 60-Hz grid systems, and those standards define the allowable levels of harmonics a DER system can inject into the local electrical system; however, the combination of many DERs and other loads, as well as utility equipment, can collectively create higher-than-expected harmonic levels. Early models of inverters and other equipment (variable frequency drives for example) have improved dramatically over the past two decades, helping to improve the harmonic content on distribution circuits.

While some utility engineers may have concerns about harmonics and similar power quality issues, they can be very difficult to model and anticipate under real-world conditions. Ensuring that DERs are listed under UL requirements is the most practical approach to avoiding problems.

[7] See standard IEEE 1366 for methods of calculating the metrics.

2.1.7.2 Voltage Sags and Swells

The ANSI C84.1 standard for voltage is one of the most important rules for operating a distribution grid system for the utility engineer and operations experts. Voltage levels outside of the ANSI C84.1 Range B should be very limited in quantity and duration, as both utility equipment and customer equipment can be damaged.



(a) Chevmain 66-kV voltage profile (b) Chevmain running volt-sec metric

Figure 2- 7. Voltage sag (left) and swell (right) measured at a substation

Source: [7]

Voltage sags are periods of time when voltage drops below the ANSI-recommended voltage levels, and voltage swells are conversely durations of time when voltage rises above the ANSI-recommended voltage levels. Both sags and swells can be damaging to loads and grid equipment and should be avoided if possible. Figure 2- 7 illustrates both a voltage sag and swell based on simulation of faults on the Western Electricity Coordinating Council (WECC) transmission paths and may indicate the response to faults by large numbers of DERs interconnected to the WECC system.

DERs should be listed and labeled under UL 1741 and operate under IEEE 1547 guidelines to effectively prevent, or at least not exacerbate, voltage sags and swells. DERs are thus programmed to autonomously respond to high voltage and reduce real power generation and to continue generating real power and, perhaps, reactive power, during voltage sags.

2.1.7.3 Flicker

Flicker on a distribution line is often seen on the load side of distribution transformers and result in the "flickering" of light sources. The sudden change in load or in generation on a circuit will create a change in voltage, and often can be seen by the human eye. Power quality specialists have long known of the flicker challenges and the electricity consumers who become irritated by the flickering illumination that occurs with incandescent light bulbs (as well as some other types of lamps). Large changes in power output by DERs can contribute to this phenomenon, and utilities must work to mitigate this challenge.

PV systems in areas with significant cloud variability may be particularly challenged by variability, causing flicker. Some regions, like the Southwestern United States, have fewer issues with cloud-based variability causing voltage flicker problems. Electric utilities must address potential flicker situations before they become problematic, as there are ample stories of angry electricity consumers who have become irritated and even irrational.

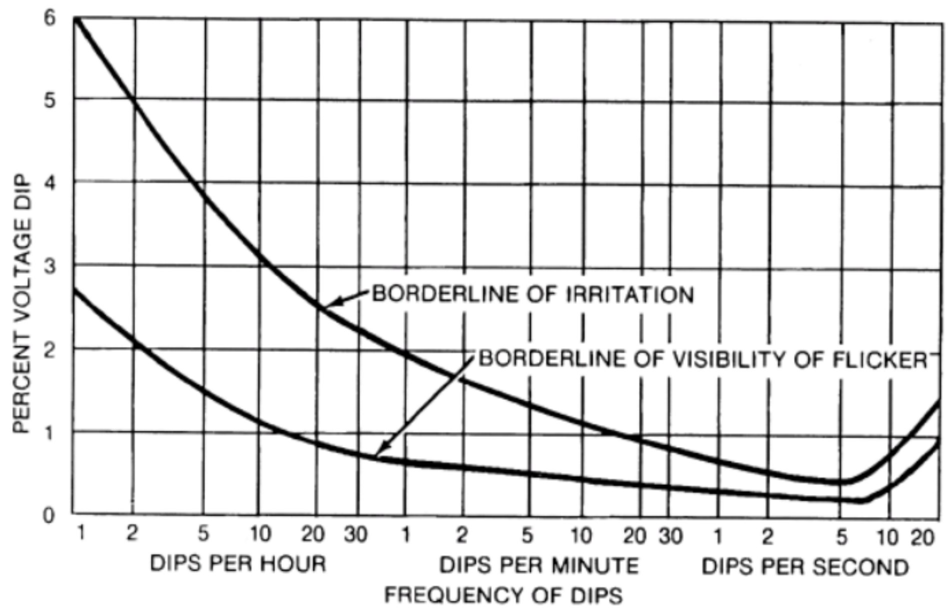


Figure 2- 8. The General Electric flicker curve illustrating the psychological impacts of flickering lights on humans

Source: [24]

2.1.8 Under-Frequency Load Shedding (UFLS) Schemes and DERs

Electric distribution engineers program substation circuit breakers to respond to emergency under-frequency situations. While these are generally rare events on the larger interconnections in North America, they can occur and may be less rare on island grid systems.

The goal of the UFLS program is to shed load when frequency begins to fall, and this often happens in the fraction of a cycle. Feeders with loads such as hospitals and prisons are often prioritized to stay energized while less critical loads are shed from the grid.

The new challenge faced with massive levels of DERs is that feeders today may have more generation than load at times of the day or night, and the programmed shedding of a circuit that is not critical in nature may exacerbate the goal of supporting frequency. New methods have been developed in some utilities to develop an "adaptive UFLS" program,[8] which seeks to ensure DERs are not shed during emergencies.

2.1.9 Distribution System Loading and Forecast Impacts

Final observations of impacts from DERs on distribution systems include the utility planning and operations departments themselves and the functions they support. Utility distribution planners must have accurate information on the system loading so they can accurately forecast when new system upgrades need to be built and deployed. Accurate forecasts of at least 5 years are important, as budgeting, permitting, and constructing facilities, such as substations and new or upgraded transmission lines, take years from start to finish.

[8] See the following for more details on Adaptive UFLS: https://www.nerc.com/comm/PC/System%20Planning%20Impacts%20from%20Distributed%20Energy%20Re/HELCO_SPIDERWG.pdf.

Having large amounts of DERs can effectively mask the true loading levels on distribution feeders and on the substations that serve them. There are few methods to accurately measure the load being served by DERs on each feeder, and some utilities utilize production meters or estimates based on interconnected systems. Switching feeder sections between adjacent feeders has been a common method to operate a distribution system, both during emergencies or when moving loads from heavily loaded circuits to more lightly loaded circuits. All of these distribution planning and system operations activities are more challenging when there are large numbers of DERs on the utility system.

2.1.10 Transmission System Impacts of DERs

While the previous subsections focus on the issues to be overcome specifically on the distribution system, to enable ever higher amounts of DER it is important to realize that DERs, in aggregate, also impact high-voltage grids and their planning and operations as well. High levels of DERs, while co-located with load in the distribution system, still impact the transmission-level dispatch and power flows as much as a single site plant with the same rating as the aggregate DERs connected to distribution systems, which are connected to a single transmission-level node. Furthermore, ever-larger shares of DERs means that ever-larger shares of the overall power system's generation is located on the distribution system. Thus, these systems, again in aggregate, need to be incorporated into transmission-level studies. The development of new models of the behavior and response of the aggregated DER will be necessary to ensure overall power system safety and reliability in the future.

Two primary impacts are discussed below. The first is the realized overall power system reduction in system inertia. This is not strictly unique to DERs but rather to all power electronic interfaced generation and load. Still, the growth of DERs, which are heavily dominated by solar PV systems connected to the grid via power electronic inverters, add to this impact. The second is the potential loss of DERs during stressed transmission system conditions (e.g., during and after a transmission-level fault or generator trip event). DERs, in aggregate, consist of a sizable share of the "dispatched" generation during daytime hours in many power systems. The key to avoiding such impacts is to design the system to avoid common action by a large number of DERs at a point in time.

2.1.10.1 Overall Reduction in System Inertia

As shown in Figure 2- 9, the grid is generally evolving from a system with relatively few large synchronous generators to a system of many smaller, and often inverter-connected, generators. With more variable renewable energy (VRE) integrated into the grid, it would become an inverter-dominated grid if more than 50% of rated power is from inverter-based devices. The major attribute that differs inverter from synchronous generators is inverters are considered as having no inertia. From a physical perspective, the real power and reactive power of synchronous generators are controlled through shaft torque and field current, respectively. And system frequency and voltages are crucial variables that are the goal of system control and must be regulated and maintained within a tight range. The mechanical inertia or kinetic energy inside the rotating components can help to counteract the fluctuations, disturbances, and variabilities through absorbing or extracting the inertia.

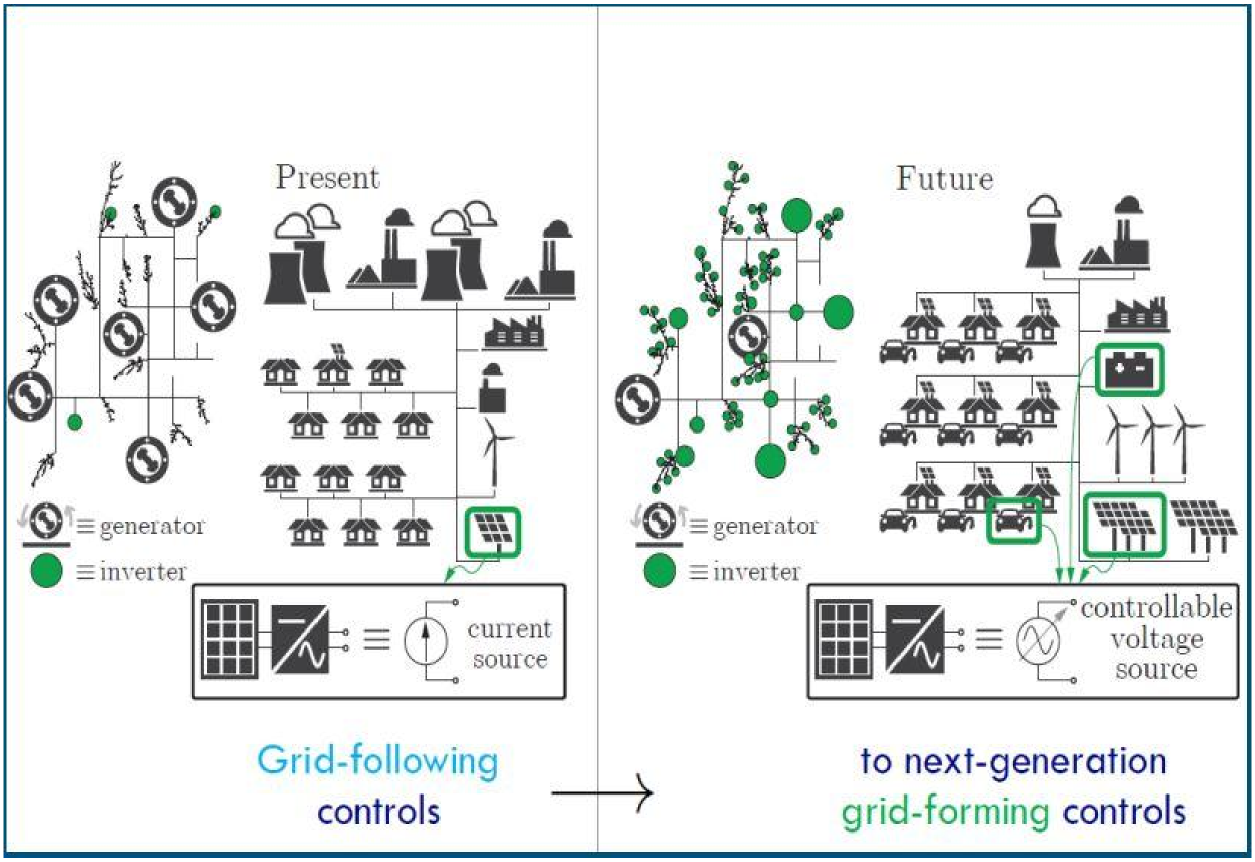


Figure 2- 9. Pictorial representation of the evolving grid from a central generation centric system to a highly distributed system

Source: [25]

It is important to note that increasing swings in frequency and voltage, resulting from power system contingencies, are not, in themselves, of utmost importance to avoid depending on the capabilities and characteristics of the generation and load fleet. For instance, power electronic grid-interfaced DERs have little trouble maintaining operation during such fluctuations if programmed to do so. Traditionally, the tight control of frequency was required due to conventional generation mechanical limitations and/or power quality concerns with synchronous motor loads. With the advent of the widespread use of variable frequency drives in many industrial, commercial, and even residential loads, many of the power quality issues may need to be reconsidered.

2.1.10.2 Voltage and Frequency Ride-Through of DERs

High levels of DERs, while co-located with load in the distribution system, still impact the transmission-level dispatch and power flows as much as a single-site plant with the same rating as the aggregate DERs connected to distribution systems, which are connected to a single transmission-level node. Furthermore, ever-larger shares of DERs means that ever-larger shares of the overall power system's generation are located on the distribution system. Thus, these systems, again in aggregate, need to be incorporated into transmission-level studies [8]. The development of new models of the behavior and response of the aggregated DER will be necessary to ensure overall power system safety and reliability in the future [9]. Further, with the development of new interconnection standards (e.g., IEEE 1547-2018) and the availability of DER interconnection equipment meeting such standards, the tools are in place to effectively make a realistic compromise between distribution system protection concerns and bulk system support during stressed conditions.

2.2 Distribution-Level Study Tools and Methods

Traditional Tools for DER Interconnection Studies

Electric distribution utilities utilize a number of computer-based tools to understand the impact of feeder design, expansion, new load additions, and, more recently, the impact of DERs. The focus of this section will be on many of the commonly used commercial tools (primarily used on 60-Hz distribution systems in North America), as well as some of the open-source tools commonly used at universities and research organizations. The main focus, of course, will be on the use of these tools and methods by electric distribution engineers working at electric utilities and consultancies in the evaluation of both DERs and loads on distribution feeders.

Electric utilities have developed or adopted both simple and complex methods to evaluate DER interconnection requests (applications for interconnection of DERs). As shown in Figure 2- 1, smaller DERs that are unlikely to cause any utility concerns, let alone problems, are often quickly vetted using the initial technical screens, which are often customized by the utility but based on the FERC SGIP [10]. These screens have been modified since the initial publication of FERC Order 2006 [11], as the number of DERs, primarily PV systems, increased across North America. Indeed, the early FERC screens were considered "low-penetration" technical thresholds but were seen more as a deterrent in many regions as the numbers of PV systems and other DERs increased from the megawatt range to gigawatt range in several states. Several industry organizations and national laboratories worked with electric utilities and FERC to make substantive changes to these technical screens [12], outlined in the latest versions of the SGIP.

The goal of modifying these technical screens, via the FERC SGIP and then through utility adoption, was to ensure DERs were not necessarily subjected to time-consuming and often costly technical modeling via the Detailed Impact Study [13] process required if technical screens are failed. For large DERs, many miles from a substation, on single-phase laterals, in voltage-constrained areas, and a host of other "trip wires," a detailed impact study using computer modeling systems is necessary to insure the ongoing proper operation of the distribution system.

Distribution Modeling Platforms and DER Impact Studies

Distribution modeling platforms have evolved since the advent of desktop and personal computers, and there were early versions on mainframe computers prior to that. These modeling platforms have become somewhat standardized between the 3,250 electric utilities in the United States and those in the remainder of North America (and other 60-Hz systems). These modeling platforms, several described below, were generally made for utility electrical distribution engineers that generally utilized the tools to evaluate new line extensions, evaluate switching options and feeder impacts, understand line loading during peak times, set capacitor banks and voltage regulators, evaluate load reach, and so on. These topics remain relevant for electric distribution engineers, and yet the advent of DERs has created new demands on this software.

Detailed Impact Studies for DER Interconnection

The standard IEEE 1547.7-2013 highlights may of the criteria that are of interest for electric distribution engineers in conducting studies for DERs (then referred to as distributed resources). The following criteria are based on the potential impacts of DERs and how to understand those impacts and define whether they will cause real problems for the utility operator and their electric power system (EPS) [13]. The impacts include:

1. *Potential for unintended islands*. Studying and modeling to understand, and avoid, a condition of an unintended island situation. "If a preliminary review determines that an interconnection for DER incorporates acceptable anti-islanding protective functions, irrespective of DER production relative to load or expected export across the point of common coupling, this sub-criterion is satisfied."
2. *Impacts on EPS equipment loading under all steady-state conditions*. The models are run to ensure that the added DERs will not have an impact on the loading of the EPS system or the voltage regulation operation:

   "If a preliminary review determines that for a single-phase DER and single-phase EPS transformer serving the facility, the gross kVA rating of the aggregated DER will not exceed the single-phase kVA rating of the EPS transformer serving the facility, it is likely that the DER will not exceed the capability of the EPS transformer and nearby EPS equipment even in the event of a loss of on-site load and this subcriterion is satisfied. For DER connected to three-phase EPS transformers, the aggregated DER per phase kVA shall not exceed the equivalent per phase transformer kVA. This sub-criterion generally applies to DER interconnected to an existing transformer."
3. *Impacts on system protection, fault conditions, and arc flash rating*.

   "The addition of DER to the existing system may necessitate changes in protection setting, protection schemes, and protection equipment. In addition, DER may introduce additional sources of short-circuit currents affecting the short-circuit duty on EPS equipment, protection settings, and alter the arc flash rating of the EPS network. DER output may also mask fault currents, interfering with the operation of protective devices."
4. *Impacts on voltage regulation within the EPS under steady-state conditions*. This criterion is simple in definition, of generally not allowing the DER to cause voltage on a circuit to go outside of +/-5% but is complex in calculation; however, the distribution modeling platforms are generally very adept at modeling the feeder, loads, and DERs to determine if a voltage violation will occur. Put another way, the "DER may create circumstances where voltage regulation requirements are violated."
5. *Impacts on EPS power quality*. While DERs must follow IEEE 1547 and UL1741, in most cases, they should meet power quality requirements set forth in the standards; however, there may be situations where there are flicker, harmonics, or other power quality problems that can occur. "Rapid fluctuation or loss of output from the proposed DER may introduce unacceptable harmonic distortion." [13]

Cluster Studies

Simply put, the cluster study process is one in which the utility engineer, or consulting engineer, studies two or more DER projects together. The benefit to the utility is that the combined DER systems and their impacts can be understood as a group, and that may also save the utility time and costs. The benefit to the DER developers may be in expediting the study process and costs for their systems as the time and investment may be split among multiple developers. These cluster studies[9] are generally used for large DER applications of several megawatts in size. A number of the modeling platforms listed in this chapter may be utilized for a cluster study.

[9] For an example, see PG&E Cluster Study Process.

Steady-State Distribution Modeling

Distribution modeling platforms generally use a "steady-state, worst-case scenario" approach to modeling a feeder or section of a circuit. When evaluating a line extension or new load, for example, the engineer/modeler will look at the peak demand time interval of the year or of several years. This will typically be some type of measured data or extrapolated data that will place the greatest burden on the equipment (conductors, transformers, regulators, and so on) and will generally offer feedback that the voltage, equipment rating, protection equipment, and other devices will be capable of serving the new loads. The data used for these worst-case scenarios generally comes from utility supervisory control and data acquisition recording data or other measuring equipment, and that is recorded as the peak load for the circuit and used for these models. Because DERs create new challenges to operating a distribution system, another approach is sometimes employed.

Quasi-Static Time Series (QSTS) Modeling

One newer approach to modeling more than the worst-case scenario is to look at snapshots in time on a feeder and run multiple models for a feeder or line section. This requires more data and more computer time, as well as capability of the computers and the software. Platforms such as OpenDSS have had this capability for years, and now the commercial platforms have adopted some of this functionality. The benefit is in being able to run multiple snapshots of both load and, in recent years, DER output and performance. QSTS model intervals may be based on daily peaks (or other data marks) or may be reduced to hourly or minute-by-minute data, whichever is deemed most useful for modeling analysis. While the time series approach may not be useful for evaluating the overall system peak loading, it can be quite informative as to the variability of voltage, power flow changes, and protection system design, among others.

Commercial Distribution Modeling Platforms

In North America, there are several common platforms that have been adopted by electric distribution utilities, and we will list several of the most prominent below. These platforms are generally used with a geographic information system (GIS) system as the basis to create extracted models for each platform, and these platforms can also be converted to the research, development, and educational platforms listed below. It is worth noting that electric utilities often adopt a platform and generally stick with that platform because of the very large investment made in buying and licensing the software, having their engineers and technicians trained on that software, and maintaining the models that have been run and simulated on those platforms.

CYME International

CYMDIST[10] is a common platform for larger, investor-owned utility distribution utilities, as well as some mid-size utilities and many consultancies that support electric distribution utilities. CYME Power Engineering Software is part of the Eaton Corporation and has been a common tool for many utilities. The CYMDIST software is referred to as a "comprehensive tool providing distribution engineers with key applications to perform system planning studies, simulations and analysis on a daily basis."

CYMDIST has been working with utilities, stakeholders, national laboratories, and industry groups to expand their software capabilities to incorporate tools that help the engineers conduct detailed impact studies of DER applications.

The capabilities and target users of this software are very similar to those of the other three software products listed on this page, and this report is not wishing to draw out differences between each platform.

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[10] See the Eaton/CYME webpage at: http://www.cyme.com/software/cymdist/ for more information.

Synergi

Synergi Electric[11] is one modeling suite among several that is part of the DNV-GL companies. This platform is designed for electrical distribution engineers and technicians, and has been adopted by utilities large, medium, and small in system size.

Synergi Electric simulation has also been adapting to the DER market and working to assist their user group in running detailed impact studies and other relevant studies surrounding various types of DERs.

The capabilities and target users of this software are very similar to those of the other three software products listed on this page, and this report is not wishing to draw out differences between each platform.

Milsoft® Utility Solutions—Windmil

The Milsoft Utility Solutions[12] suite has several platforms for electric utilities, and the platform used for power system engineering analysis is Windmil. It is worth noting that the Milsoft suite of software has been closely aligned with the electric cooperative utilities in the United States and North America, while still used by other types of electric utilities (municipal, investor-owned utility). Because of this close relationship, the software is closely aligned to work with other platforms that cooperatives have adopted, including the GIS and customer information system, among others.

Milsoft Windmil, like the other platforms, has been working to adopt new capabilities that help engineers evaluate DER interconnection applications and create detailed impact studies.

The capabilities and target users of this software are very similar to those of the other three software products listed on this page, and this report is not wishing to draw out differences between each platform.

Distributed Energy Workstation (DEW)

DEW is a software package developed by Electric Distribution Design and is an NISC company. The DEW/ISM platform provides analytical tools to assist utility engineers and consultants solve utility distribution problems or evaluate the impact of system changes and new loads. DEW works with larger, medium, and small utilities in a fashion similar to other commercial platforms and is led by engineering professors and a team of Ph.D. electrical engineering experts.

DEW, like the other platforms, has been developing and rolling out new capabilities that assist utility engineers evaluate interconnection requests for DERs as well as help in completing detailed impact studies for larger DER applications. DEW has been active in work with national laboratories and U.S. Department of Energy (DOE) project teams, but they are not alone in their endeavors, as the other commercial and research, development, and educational platforms are active in new projects focused on DER integration.

The capabilities and target users of this software are very similar to those of the other three software products listed on this page, and this report is not wishing to draw out differences between each platform.

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[11] See the Synergi/DNV-GL webpage at: https://www.dnvgl.com/services/power-distribution-system-and-electrical-simulation-software-synergi-electric-5005 for more information.

[12] See the Milsoft Engineering Analysis webpage at: https://www.milsoft.com/engineering-operations/engineering-analysis/ for more information.

Research, Development, and Educational Distribution Modeling Platforms

OpenDSS

OpenDSS[13] is an EPRI platform that was opened for general use years ago after initial development in 1997. This powerful tool is constantly evolving and is capable of being customized by developers who wish to add on specific functionality. The platform is "an electric power distribution system simulator designed to support DER grid integration and grid modernization."

The platform is a common tool at universities that have electrical engineering programs, and with the new focus on electric distribution systems over the past 15 years, along with the intense focus on DERs, the tool is a common application for universities and their students.

OpenDSS was an early adopter of the QSTS approach to evaluate circuits at variable time sequences, which is more important for understanding the potential impact from DERs. And the tool has also been the platform for the EPRI DRIVE tool for developing feeder-wide studies and creating grid-hosting capacity maps. These maps are one of the most recent innovative tools that are now required in many U.S. states as utilities publish colored maps that illustrate the amount of DER that can be hosted in specific locations by using "heat maps."

The OpenDSS platform continues to be a powerful research and development tool, allowing students, teachers and researchers the opportunity to customize the data evaluated along with the new functions that are needed for advanced devices, such as smart inverters.

GridLAB-D

The GridLAB-D tool is a set of simulation software that was developed by and supported by the Pacific Northwest National Laboratory and DOE. While this software platform offers many of the capabilities of the other research, development, and educational platforms and commercial platforms, it also adds the ability to model elements within a building or behind the meter of an electricity user.

"GridLAB-D is a flexible simulation environment that can be integrated with a variety of third-party data management and analysis tools. The core of GridLAB-D has an advanced algorithm that simultaneously coordinates the state of millions of independent devices, each of which is described by multiple differential equations" [14].

This platform is also a common tool used by university students, teachers, and researchers, as well as other research institutions. The platform has additional capabilities to better design and simulates systems such as communications, smart metering, and open modeling framework.

Distribution Modeling Areas of Common Focus

Voltage Profiles

Adding new line sections and new loads onto a distribution circuit will have an impact on voltages, near the proposed load and often on other sections of the feeder. Distribution modeling platforms are ideal for evaluating the voltage ranges on a feeder and are a common approach for evaluating new, typically larger, loads.

Evaluating system devices such as voltage regulators and capacitors is also an excellent use for the voltage evaluation functions in various tools. Figure 2- 10 is an illustration of the voltage profile that can be illustrated using tools or data from the tool output. The modeling platforms generally provide map-

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[13] See the EPRI webpage at: https://www.epri.com/pages/sa/opendss?lang=en for more information.

based heat diagrams (using GIS data) that show levels of voltage throughout the circuit, while this figure illustrates the level of voltages over the distance from the substation.

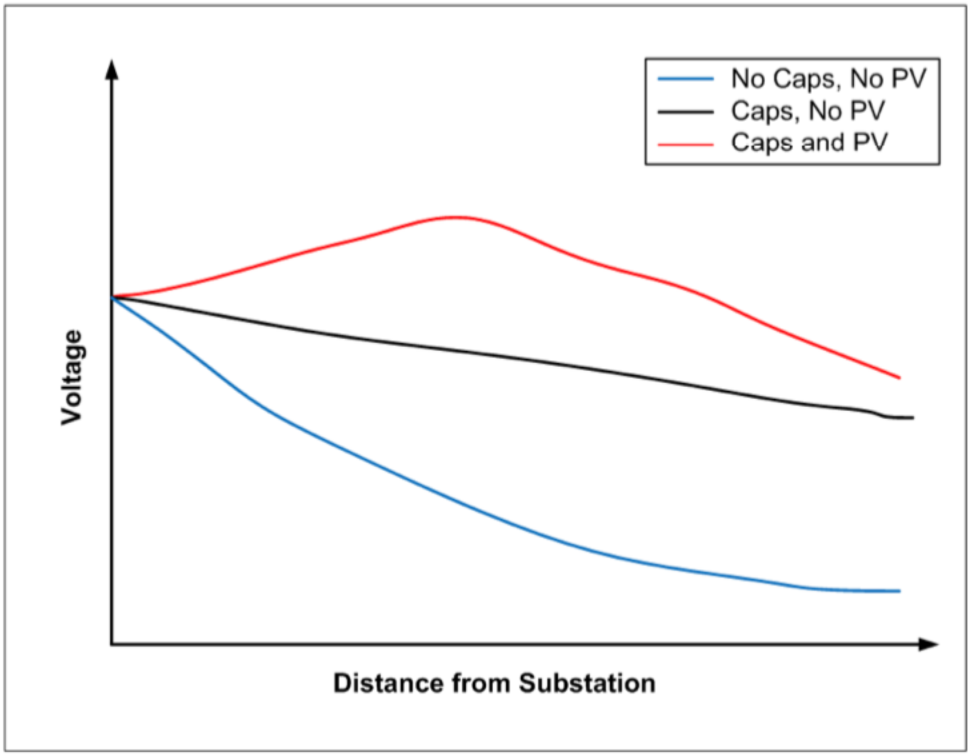

Figure 2- 10. Voltage profile showing impacts from PV and capacitor banks on a circuit

Source: [17]

The ANSI C84.1 national standard (see Figure 2- 3) has two ranges, A and B. Range A, or +/-5%, is often the guiding range for distribution engineers to maintain, as equipment may be damaged if the voltage levels go outside Range A or B for longer periods of time. Generally, the modeling platforms will highlight or alert the modeler if voltage levels get outside Range A of the ANSI standard.

Temporary Overvoltage and Transient Overvoltage

Steady-state distribution modeling platforms often have limited capability to model temporary overvoltage or transient overvoltage because they occur in a more transient manner. Both overvoltage phenomena are generally a result of DER installations, rather than customer load events. Load rejection overvoltage events and single-phase loss overvoltage are two primary factors in the cause of overvoltage situations [15] [16]. Figure 2- 11 illustrates an example of temporary voltage violations. It should be noted that both temporary and transient overvoltage modeling are challenging, and the modeling platforms may struggle to identify possible cases of overvoltage concerns. Often the electric distribution utility engineer must recognize this potential problem and seek to mitigate this as a standard approach for DER systems that are often larger systems and typically three-phase systems. The *NREL High-Penetration PV Integration Handbook for Distribution Engineers* (page 10) provides a detailed description of these phenomena [17].

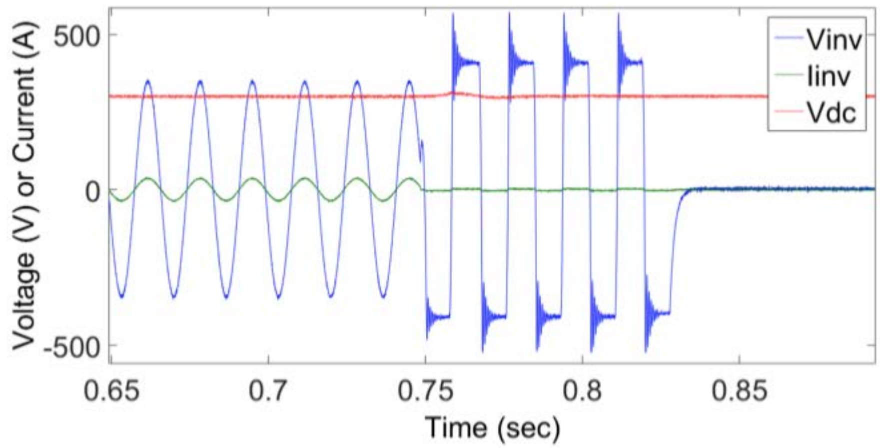

Figure 2- 11. Example of temporary overvoltage due to load rejection

Source: [17]

Reactive Power Flow

Distribution engineers will often utilize standard modeling platforms to evaluate both real power and reactive power (volt-amp reactive [VAR]). Because current flow and voltage calculations are key metrics for modeling platforms, it is vital for the model (and the engineer) to understand the types of current flow, including the current to and from DERs. The VAR calculations and measurements are an important factor into the voltage levels on a circuit, and help the system determine if capacitor banks should be installed and how they should be controlled.

Many utilities utilize capacitor banks on the distribution lines to supply reactive current for the various loads on the feeder, and this is an extremely important factor in reducing VAR flow on transmission lines (generally unwanted) and to maintain proper voltage levels along the circuit. There are some utilities that rely heavily on capacitor banks and VAR flow to manage voltage levels, while many utilities rely on the substation transformer load tap changers and/or voltage regulators to accomplish that function.

Finally, it should be noted that the newer inverters (UL 1741SA and more recent) can be set to absorb reactive power (or to supply reactive power) as a tool to maintain voltage levels. If there are large amounts of inverter-based DERs on a circuit, with many set to absorb VARs, there will be a greater need for capacitors on that circuit, typically near the substation. This is an area of importance that will require the modeling platforms to simulate the "volt-VAR settings" on inverters.

Power Flow

Sometimes referred to as "load flow," this is a key function of all distribution modeling platforms and encompasses real current, reactive current, voltages, and loads on a circuit. Ultimately, this is important on many fronts for the utility engineer, and perhaps, most importantly, is the ability of the feeder to serve existing and new loads without voltage problems or system overloads.

DERs on a circuit change the inherent flow of power as they often can reduce the power flow (during the day for PV systems, as an example) and may back feed power onto the system and create multidirectional power flow at times. DER power flow can impact voltage, current levels (real and reactive), and of course change the protection coordination that is so important for all distribution systems (protection coordination is typically handled in different modeling modules or other dedicated protection modeling programs).

Load Evaluation and Load Reach

Basic to commercial and research, development, and educational model platforms is the evaluation of new line extensions that are generally necessary for serving new loads and, more recently, serving DER systems. Feeders generally grow in an organic manner, expanding as homes and businesses grow in communities, while some are landlocked and change only when there is a change in business operations and expansions.

Modeling new loads and future expansions that are part of a distribution utility forecast is an important feature in understanding if a feeder has the capacity to serve new loads and if they have the ability to serve new loads farther away than the years prior. If the model determines that voltage will be outside of the ANSI C84.1 range, or if the circuit conductors and equipment may be overloaded, it will inform the planning electrical engineer and other departments if new circuits must be built or, in some cases, if new substations should be planned (which will impact the plans of other departments, such as electric operations, substation engineering and operations, and transmission system planning). Of course, large amounts of new load may have an impact on the need for generation capacity, but that is outside of the scope of this discussion.

Forecasting Models and Tools

As noted in previous sections, the load evaluation and load reach model runs can highlight the need for system changes that include forecasts of new feeders, substations, and other capital equipment expenditures. In a bottom-up planning scenario, engineers and distribution planning departments track annual load forecasts and project several years forward to understand and plan for system expansion. Modeling platforms help them in concert with supervisory control and data acquisition and operations departments that track peak loading on feeders, substations, and the bulk power system. As new building is proposed by developers and expansions by companies, utilities create multiyear planning forecasts that are then simulated in power flow computer models. The results of these model runs show the engineers and planning departments where system upgrades will need to be considered and when those upgrades will be needed.

These feeder-focused models run on multiyear load growth simulations then inform other utility departments so they can plan for new substation transformers, feeder breakers, entirely new substations, and the expansion of transmission and the bulk power system. And the utility governance generally has a top-down forecast that will then dictate how much capital will be available for projects, creating the need for a hierarchy of project needs. The most pressing projects will have the highest priority, and other projects may get pushed out one or two years until funding is available. The computer forecasting tools are critical in the decision-making process, and help the utility expand their system at the proper time and avoid unnecessary over-building (where feeders may be oversized and capital expenditures cannot be justified).

Publications such as the *Power Distribution Planning Reference Book* [26] are excellent tools that, used in conjunction with computer models, help distribution planning engineers evaluate options, set priorities, and maintain system reliability and power quality while minimizing the capital expenditures.

Grid-Hosting Capacity (GHC) Tools for DERs

Electric distribution utilities may use GHC to streamline the interconnection process by using a predetermined hosting capacity level, together with the current adoption levels and anticipated DER growth. The GHC output creates maps (as the information is typically presented; see Figure 2- 12) and often evaluates levels of DER deployment beyond the basic technical screens. GHC information may allow larger DERs to pass the interconnection approval process without going through a detailed impact study, as the GHC methodology is essentially a feeder-wide detailed impact study. GHC can also be used for long-term distribution planning to help utilities identify the infrastructure needed to accommodate anticipated DER growth and target DERs in areas with higher GHC. GHC analysis is also valuable for DER developers because it allows them to identify locations where it might be easier to add new DERs or areas that would likely require infrastructure upgrades, allowing them to evaluate project locations upfront rather than having to guess or wait for a utility analysis.

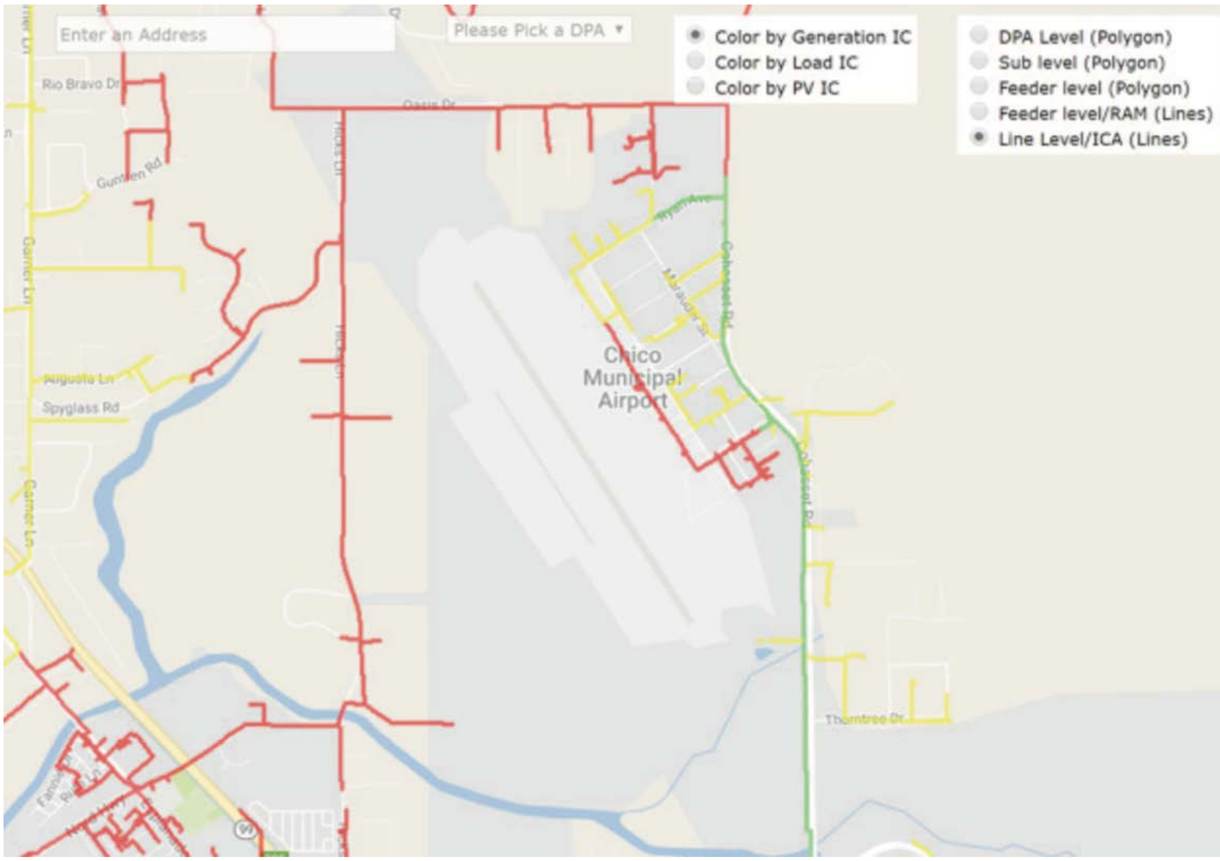

Figure 2- 12. Example of GHC map in PG&E territory

Source: [27]

A GHC analysis generally consists of a series of automated distribution system analyses. This analysis is then repeated for increasing amounts of randomly interconnected DERs, until one or more of the analysis results exceeds a predetermined threshold. These thresholds or evaluation criteria for the hosting capacity analysis focus on four main areas:

1. Voltage
2. System protection
3. Thermal limits of equipment
4. Power quality.

Challenges utilities face related to hosting capacity analysis include coordinating data between systems and the large amount of information required, including feeder models, loads, and DER characteristics.

The commercial platforms generally have provisions for hosting capacity analysis. CYME has an add-on module that uses the iterative method—the CYME Integration Capacity Analysis module.[14] Synergi is also able to conduct hosting capacity analysis using the iterative method. The EPRI DRIVE tool can interface to the commonly used distribution system analysis tools, OpenDSS, CYME, Synergi, and Milsoft Windmil. The implementation of the EPRI DRIVE approach has been customized based on specific database structures and data sets in various tools.

Computer Modeling Tools for Smart Inverters (PRECISE™)

Advanced power electronics used in DC to AC power inverters are often referred to as "smart inverters" and are generally listed and labeled under the UL 1741SA standard (or latest version). With the proliferation of millions of DERs in North America alone, the utility and manufacturing industries realized the need for inverters that can support the grid and ride through voltage or frequency disturbances. These advanced inverters can also support voltages on the distribution circuit by absorbing or exporting reactive power, and there are many other functions available to support the local utility requirements as well as the local electrical system needs.

Many of the new smart inverter functions are not an "on" or "off" setting but have a continuum of setpoints for many of the functions [18]. Voltage control settings may be quite different near the substation on a feeder, compared to those miles away from the substation. And the distribution utility may have other concerns that need to be evaluated and decided at the time of the DER interconnection application approval.

NREL and the Sacramento Municipal Utility District have developed a tool for utility engineers to quickly run an analysis and recommend the necessary set points for a DER system [28]. The PRECISE tool uses many of the data points that other modeling tools utilize, including the GIS data and customer information service load data, and leverages the power of OpenDSS to quickly evaluate a proposed DER installation. PREconfiguring and Controlling Inverter Set-points, the winner of the 2019 R&D100 Award, combines detailed distribution system modeling with the analysis of grid conditions to provide custom solutions to grid stability—a key to high DER penetration operations. Figure 2- 13 illustrates the optimal range of voltage support to reduce losses and maximize customer generation using DERs.

[14] See http://www.cyme.com/software/cymeica/.

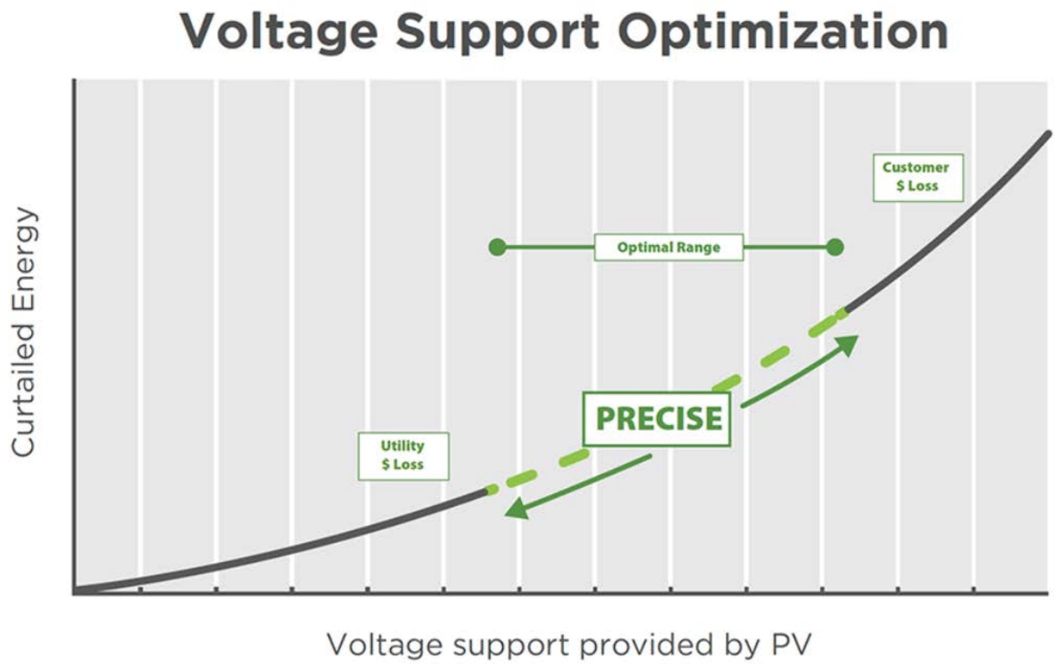

Figure 2- 13. Illustration of PRECISE voltage optimization using smart inverter functions

Source: [28]

The PRECISE tool is an important step forward in helping utilities quickly configure inverter and DER settings, but much work remains; there are over 20 functions that inverters can provide and their location, time of day, seasonal impacts, and local load behavior may need to be carefully and quickly modeled for maximum efficiency and reliability going into a high DER penetration future.

Smart Inverters and Gaps in Distribution Modeling Platforms

While tools such as PRECISE help utility engineers determine the best settings for smart inverters, there is still a tremendous need for the commercially available distribution modeling platforms to accurately portray various DER systems and specific inverter models. This has been a consistent request for years in meetings and discussions, in that DERs behave differently depending on manufacturer and the settings applied to the inverter control.

With over 20 functions available, newer (smart) inverters have a multitude of setpoints available and these need to be available for modeling systems. Because inverters can now have an infinite variety of settings, those settings need to be recorded and captured in the data files of GIS systems. It should be noted that distribution utilities often settle on a limited number of inverter configurations and having a standardized set of configurations will make the task of deploying DERs and modeling DERs much simpler for all stakeholders.

Transient and Dynamic Models for Distribution Systems

As stated earlier in this document, traditional distribution modeling platforms evaluate a snapshot in time, often during the peak demand interval for a particular year. This is just not helpful enough when evaluating impacts from new devices such as DERs and other systems such as demand response. And so many of the modeling platforms have evolved to allow the QSTS method of evaluating multiple snapshots in time, not necessarily during the peak time but a more accurate evaluation of how a feeder may perform over the course of a day, a month, or a year. A modeling platform and its user can evaluate hundreds or thousands of snapshots in time, as long as they have the appropriate data for the system to operate, as well as a powerful computer and/or a lot of time to wait for results.

Beyond the QSTS approach of a series of static snapshots is a growing desire to understand the dynamic and transient nature of distribution circuits, loads and DER systems. Traditionally the realm of the Transmission System Planning Engineering Departments, transient and dynamic stability analysis is now under consideration on distribution system modelers.

A major challenge faced by those who wish to model dynamic and transient responses is a lack of modeling software and a lack of data for those tools. Researchers and members of groups like the IEEE Power Engineering Society are working to develop new tools that will allow the evaluation of DERs and fleets of DERS, along with loads, on distribution systems [19].

Modeling Other Emerging Technologies

Finally, it should be noted that there are many changes afoot in the distribution realm, and many new systems and operational configurations will eventually need to be modeled. For instance, battery energy storage systems (BESS) have over two dozen possible operational applications, of which many can be stacked to increase value, and the modeling of those applications will need to be developed for distribution modelers [20]. And loads or DERs that respond to signals or price changes will also have a significant impact on distribution systems and will likely need to be modeled as power flow can change quickly. The following are examples of systems that will affect the performance of a distribution system(s) and will likely need to be modeled in the future:

- Energy storage (BESS)
- Demand response loads
- Microgrids and other customer generation
- Electric vehicles and future vehicle-to-grid systems
- Smart buildings.

It is abundantly clear that distribution modeling platforms will need to evolve as distribution systems continue to change in dramatic fashion. As advanced tariffs roll out to control smart buildings and other demand response systems, and as DERs continue to be rolled out in large numbers and in the gigawatts, there will need to be continued research, development, training, and modifications to these distribution modeling platforms.

2.3 Integrated Transmission and Distribution Tools

While traditionally studied separately, transmission and distribution systems are, of course, inherently linked, and the power system cannot reliably operate without both systems (other than for completely isolated microgrids). With many grid modernization trends, but also specifically for the increasing levels of DERs, it is becoming necessary to more closely investigate the interoperation of the transmission and distribution system. The tools discussed in this section are not specifically meant to be used for routine studies or, for instance, should it be assumed they would be the tool of choice for all DER grid integration studies in the future. The tools presented are representative of the current state of the art of transmission and distribution co-simulation meant primarily for research purposes. Still, the insight provided by these tools is valuable. Some power system questions require the investigation of the transmission and distribution interface with relatively high resolution. Other times, transmission and distribution co-simulation may simply show cases where separate transmission and distribution simulation is still valid and a more accurate solution, or more insightful analysis, is not worth the extra modeling requirements and computational burden.

Integrated Grid Modeling Systems (IGMS)

Traditionally, utility circuit modeling tools allow an engineer to model an individual feeder or section of a feeder to understand the impact of changes in line size, length, upgraded equipment or newly connected loads, and DER. The outputs of these model runs would generally only be shared with the transmission system planning engineering teams when the distribution system models highlighted the need for a system change (i.e., the need for a new substation or large substation upgrades). There previously was not a method available to simulate all distribution systems in a utility service territory and simulate the impact on the transmission and bulk power system. To do such a thing would require a large data set, consisting of all the distribution system models, load profiles, generation profiles, and so on, and a high-performance computer to analyze such a large system.

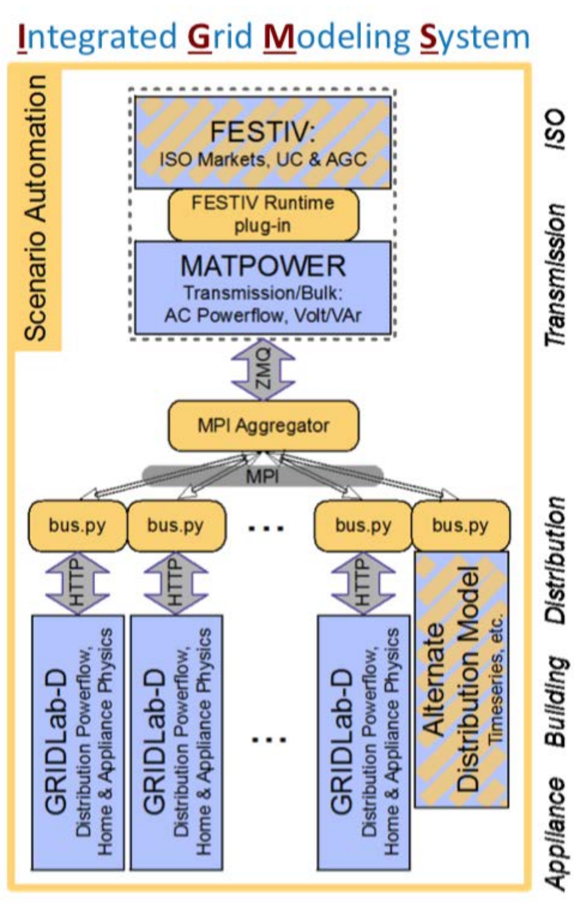

Figure 2- 14. The IGMS platform developed by NREL

The IGMS (Figure 2- 14) is an integrated distribution-transmission tool and leverages the simultaneous output of all the distribution feeders in a utility system to understand system-wide impacts on the transmission and bulk power system, as well as a large number of DERs tied to the various feeders [21].

The advantages of IGMS over other existing co-simulation methods are as follows:

- Including multiperiod market dynamics, which is capable of simulating wide spreading times windows from day-ahead unit commitment to 2 seconds automatic generation control (AGC)

- Analyzing large-scale power grids that contain thousands of transmission nodes, full-scale distribution feeders, and tremendous end-use customers
- Including various tools for data processing, simulation scenarios, run coordination, and output processing.

Each model in IGMS is a specific domain of the power system; however, information can be transmitted among different models.

The simulation range of IGMS covers a wide variety—from appliance all the way up to independent system operator (ISO). IGMS-Interconnect let smooth communications among those models, and there are many message buses to ensure the exchange of information among bulk power systems. Two Python modules are responsible for information exchange between transmission to substation and substation to feeders. FESTIV Runtime plug-in enables the communication between different bulk power markets. The interaction between transmission and distribution is accomplished by Bus Aggregator. The connections between transmission bus and feeders are supported by bus.py.

The integrated tools in IGMS are well-established tools that are also open source/free, compatible with Linux, and have script interface. The IGMS co-simulation framework aims to simulate the hierarchical structure of the electric power grid. IGMS is also capable of matching a transmission line with its feeder buses. The improvements of IGMS are in three major aspects: (1) feeder population increases; (2) increased GridLAB-D interfacing speed; and (3) performance and memory balancing across ranks. IGMS analysis has concentrated on the impacts of distributed PV on the transmission level; it can be easily extended to the simulation and analysis on other DER technologies.

IGMS can inform utility engineers, as well as operations and energy scheduling departments, and help utility and bulk power system operators understand the impact of thousands or millions of DERs on a utility system simultaneously. IGMS simulations of full-scale transmission and distribution systems (>1 million buses) showed how increasing grid operator visibility and forecasting for PV-based DER can significantly reduce production costs (18% versus no awareness) while improving reliability metrics such as the NERC CPS- 2 metric and statistical measures of area control error.

Currently, the IGMS simulation core is incorporated into Hierarchical Engine for Large-scale Infrastructure Co-Simulation (HELICS) tool [4]. HELICS began as the core software development of the Grid Modernization Laboratory Consortium project on integrated Transmission-Distribution-Communication simulation supported by the U.S. Department of Energy’s Offices of Electricity Delivery and Energy Reliability and Energy Efficiency and Renewable Energy (EERE). As such, its first use cases center around modern electric power systems, though it can be used for co-simulation in other domains. HELICS’s layered, high-performance, co-simulation framework builds on the collective experience of multiple national labs. HELICS was designed to support very-large-scale (100,000+ federates) co-simulations with off-the-shelf power-system, communication, market, and end-use tools; it has been built to provide a general-purpose, modular, highly-scalable co-simulation framework that runs cross-platform (Linux, Windows, and Mac OS X) and supports both event driven and time series simulation. It provides users a high-performance way for multiple individual simulation model “federates” from various domains to interact during execution–exchanging data as time advances–and create a larger co-simulation “federation” able to capture rich interactions. Written in modern C++ (C++14), HELICS provides a rich set of APIs for other languages, including Python, C, Java, and MATLAB, and has native support within a growing number of energy simulation tools.

Modeling the Impact of DER Voltage Ride-Through Settings

The dynamic modeling for transmission systems is very common and is regularly undertaken to assess the expected operation of the system for transmission-system disturbances such as the loss of large generators and transmission-system faults. Conversely, dynamics are rarely studied on the distribution system, as the traditional operation of the system simply does not require it. With the introduction of large aggregate amounts of DERs the amount of generation within the power system, at least for certain hours of the day, is sizeable. While no large impacts, at the transmission- or distribution-level, are expected should a few DERs trip offline regardless of the cause; however, it might be possible that transmission-level contingencies could result in the coordinated tripping of DERs within a relatively large region [92]. If the amount of DER in this region is high enough, the combined aggregate tripping of DERs would effectively be a cascaded loss of generation—potentially leading to system reliability issues and concerns. This was the specific reasoning behind the development of a comprehensive set of voltage and frequency ride-through performance categories in IEEE 1547-2018.

The inclusion of multiple choices of voltage ride-though categories (i.e., settings) begs the question as to how the settings should be chosen. To help inform these decisions, a transmission and distribution co-simulation method was developed that integrates balanced three-phase dynamic modeling methods, typically used for transmission dynamic modeling, with QSTS distribution system analysis [7]. Figure 2-15 shows a block diagram flow of the solution and the interconnection of the multiple modeling tools. The dynamic transmission model effectively models the dynamic response of the transmission system as normal but the voltage profiles at the interface of the transmission and distribution system (i.e., the substation) are then used as an input to the distribution simulation. The purpose of the distribution system analysis is to model the voltage present at each distribution system model node connected to a DER. Further, within the distribution system model there are "DER agent" models that accurately represent the response of a DER (staying on, tripping off, reducing output, and so on) depending on the specific voltage waveform seen at its point-of-common-coupling. The expected responses of the DERs present within the distribution system connected to a transmission simulation node are then communicated back to another transmission simulation where the built-in positive sequence models are "modulated" with the expected DER generation profiles.

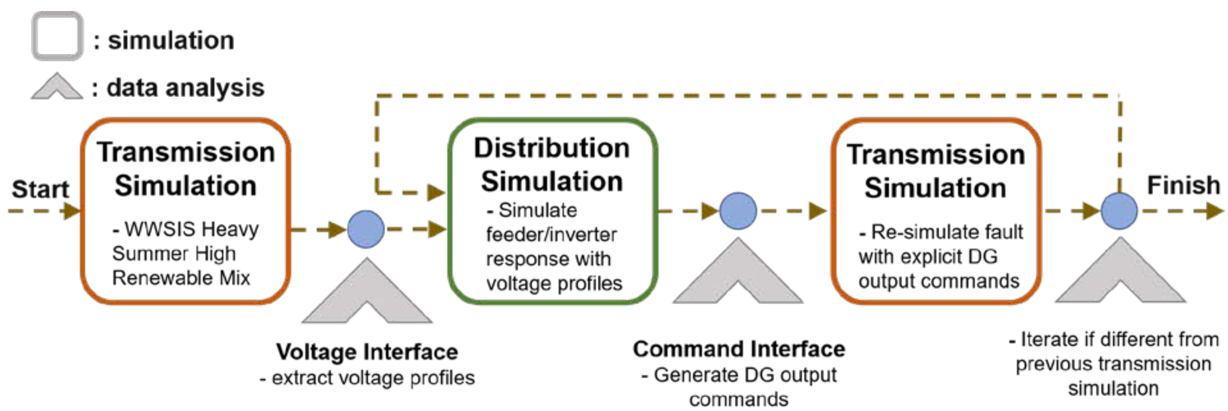

Figure 2- 15. Dynamic/QSTS analysis co-simulation flow implemented in DER voltage ride-through impact study

Source: [7]

It should be noted that this co-simulation is "very loosely coupled," meaning that the convergence of the transmission simulation and distribution simulation are not coupled except via iteration of the distribution and transmission simulation loops as shown in Figure 2- 15.

The results from a study completed using this technique are shown in Figure 2- 16 [7]. The results shown in this figure include dynamic modeling of the entire U.S. Western Interconnection, 123 distribution circuits, representative of the distribution system at 123 transmission nodes, which were most impacted for a three-phase low impedance fault on a 500-kV system bus and over 6,000 individual DERs interconnected on the 123 distribution circuits. The amount of DER-based generation is shown for the three IEEE 1547-2018 performance categories, a worst-case IEEE 1547-2003 response and all are compared to the modeled response using dynamic transmission system modeling only (labeled as "no-inverter commands"). Information like that presented in the figure can steer specific settings for DERs, in terms of interconnection requirements, and maintain high levels of system reliability and resilience even with very high levels of DER deployment.

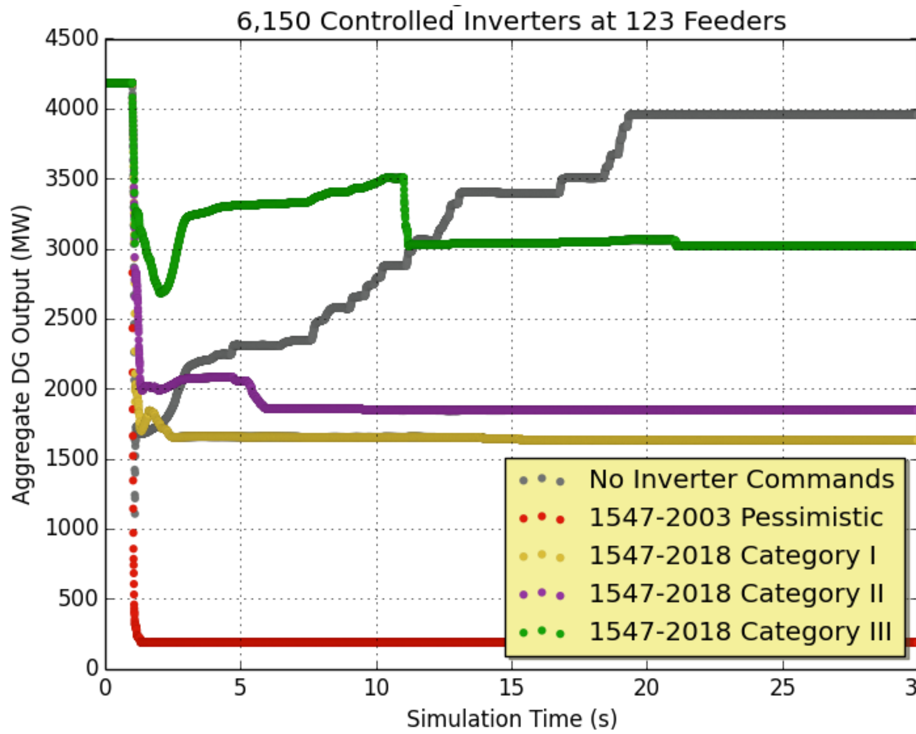

Figure 2- 16. Example of aggregated DER generation following a transmission-level fault for different IEEE 1547-2018 voltage ride-through performance categories

2.4 Conclusions

The continued growth in DERs is fundamentally changing the way the distribution system is operated and planned. Additionally, an increasing number of grid issues are being regularly experienced by distribution engineers within an increasing number of utilities. Fortunately, these fundamental changes and increasingly regular issues are being addressed via continual improvements in existing distribution system modeling tools—for tools used by both industry and researchers—and via novel modeling methods, which are combining transmission and distribution system modeling to investigate new, often complex, system interactions at the transmission/distribution power system interface. As DERs continue to increase more and more utilities, regulators, and developers are finding usable solutions in the deployment of smart inverters with ever more capable functionalities. This increase in functionality is welcome but comes at the cost of more complex analysis when determining what specific settings should be used for an individual interconnection. With more time, experience, and likely the further development of advanced analysis tools, even higher levels of DER integration will result in a reliable, resilient, low-cost, and safely operating grid.

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