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Impact of IEEE 1547 Standard on Smart Inverters and the Applications in Power Systems

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IEEE PES Industry Technical Support Leadership Committee

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IEEE PES INDUSTRY TECHNICAL SUPPORT LEADERSHIP COMMITTEE

Prepared for
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U.S. Department of Energy
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IMPACT OF IEEE 1547 STANDARD ON SMART INVERTERS AND THE APPLICATIONS IN POWER SYSTEMS

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Preface

In 2016, IEEE signed a Memorandum of Understanding (MOU) with the U.S. Department of Energy (DOE) to address grid modernization challenges. The IEEE objective is to provide independent and unbiased viewpoints on important technical issues by leveraging IEEE membership, including Technical Committees and chapters. IEEE PES has formed the Industry Technical Support Leadership Committee (ITSLC) to facilitate global collaboration between the IEEE and governments, regulatory, and other industry organizations, such as the U.S. DOE, and to provide fast response as required by changes that our industry is experiencing. The ITSLC Force works closely with the IEEE Standards Association (SA), IEEE-USA, and other societies.

As part of the collaboration initiative, the U.S. DOE has asked IEEE to develop a whitepaper on the impact of IEEE 1547 standard on smart inverters and the applications in Power Systems. IEEE has formed a “fast-track” Working Group of industry experts to respond to this request in a timely fashion. This whitepaper is a revision of the whitepaper that was published in 2018 as a result of the work with a purpose not only to support the U.S. DOE initiatives in this important area, but also to provide important information and education to IEEE membership.

On February 12, 2020, the Board of Directors of the National Association of Regulatory Utility Commissioners (NARUC) unanimously approved a resolution offered by Commissioner Schuerger (MN) recommending state commissions adopt and implement the newly revised distributed energy resource interconnection standard (IEEE 1547-2018.) The resolution also unanimously passed two NARUC committees: Electricity and Energy Resources and the Environment. The resolution grants flexibility for state commissions recognizing the unique procedures, priorities and needs for each state; while recognizing the best practices identified by technical experts and IEEE 1547-2018 for convening a stakeholder process, utilizing existing research and experience to make evidence-based decisions and aligning the implementation of the standard with the availability of certified equipment. A copy of the final resolution is available at [63]. In anticipation of renewed interest and increasing need for education, this white paper has been updated to reflect the latest knowledge on adopting IEEE 1547-2018.

This white paper presents smart inverter features along with the implementation challenges and potential solutions. The paper starts with an introduction to smart inverter functions. It then describes the smart inverter modeling, protection, power quality, ride-through, distribution planning, interoperability, and testing and certification. This updated version also includes an anticipated timeline for when smart inverters compliant with IEEE 1547-2018, certified through a new UL 1741 Supplement B, may become available in the marketplace.

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1.0 Introduction

The penetration of distributed energy resources (DER) technologies in the electric grid, especially solar photovoltaic (PV) generation¹, has been increasing rapidly and could become a major participant of the electric generation, thus the need for advanced features that can minimize their impacts. The national standard IEEE 1547-2003 that covers DER DG generation performance was written for low penetration scenarios where DER was insignificant and could be removed/disconnected from the electric grid without compromising grid stability. The new IEEE 1547-2018 standard will remove limitations of its predecessor and furthermore will add the capability of advanced features on DER, like smart features to solar Photovoltaic (PV) inverters². Smart solar PV inverter features comprise, at minimum, the following: voltage ride-through, frequency ride-through, voltage support, frequency support, and ramp rates. Both voltage and frequency support can be achieved by Various means that will be covered in detail in the later sections. These features can minimize solar PV inverters generation potential negative impacts due to remote or local system grid events, voltage and/or frequency. The IEEE 1547-2018 standard enables new DER to have the capabilities for grid-supportive functionality, and the applicable authorities governing interconnection requirements can utilize these advanced features to provide more reliable and resilient energy to their customers as the power system continues to evolve [60], [61].

California and Hawaii Investor Owned Utilities (IOUs) have experienced the highest penetrations of DER in the country and have adopted smart solar PV inverter features in their DER IOU standards (California Rule 21 and Hawaii Rule 14H). California started requiring smart solar PV inverters September 1, 2017 to try to minimize their impacts in the grid. Most adjacent municipalities do not require smart solar PV inverters thus leaving the IOUs to support the grid during grid events. The following subsections cover in detail the performance of smart solar PV inverters features.

1.1 Voltage Ride-Through

The former DER standard IEEE 1547-2003 only provides maximum allowable voltage disconnection time ranges; an example is if the voltage falls anywhere between 50 and 88 percent the DER shall disconnect within 120 cycles (2 seconds); meaning that the DER can disconnect within 1 cycle or 120 cycles (2 seconds) and will still be in compliance. In order to eliminate this limitation, the new IEEE 1547-2018 includes both mandatory minimum voltage ride-through and trip times for under- voltages and over-voltage events.

Since the IEEE 1547a-2020 amendment provides more flexibility for adoption of abnormal operating performance Category III, most smart inverters are anticipated to be required to meet that capability, even if the utility-specified voltage trip settings lead to partial utilization of that capability. Furthermore, IEEE 1547-2018 constraints the voltage region in which smart solar PV inverters are allowed to switch to momentary cessation, an operating mode in which inverters block current injection that, if not constrained, could lead to bulk power system reliability issues. Instead, smart inverters are

¹Other types of distributed generation include (but are not limited to) wind, small hydro, bio-mass, bio-gas, small conventional generators, regenerative motors and dynamometers.

²Note that IEEE 1547-2018 applies to all DER, independent of technology. That includes DER with synchronous generators as well as other inverter-based DER like wind turbines and fuel cells.

required to continue to provide current during voltage ride-through, based on pre-disturbance operating point or voltage regulation mode.

Since the time constants of the steady-state voltage support are long compared to the ride-through period, they provide only little reactive support during the abnormal voltage condition.

A specification of dynamic voltage support during abnormal voltage conditions, for example by injecting reactive current with priority over active current was intentionally not included in the standard and has been deferred to a future revision. Given potential challenges to coordinate that function with existing distribution protection schemes, and the fact that there is no standard test procedure to certify that function in the newly published IEEE 1547.1-2020, it could be premature to require dynamic voltage support from smart inverters for the time being.

1.1.1 Outlook

Dynamic voltage support during abnormal voltage conditions is not required by IEEE 1547-2018. This gap could be filled in a future revision of the standard. Figure 1 shows a smart solar PV inverter performance during a voltage event (under-voltage and over-voltage). It shows how a smart inverter could ride through the under-voltages and over-voltages (V_{SYSTEM}). In this particular setup, the smart inverter is capable of providing dynamic voltage support during abnormal voltage conditions and starts injecting reactive current ($Q_{INVERTER}$) to support the system voltage (V_{SYSTEM}) when it sags at 2 seconds time-mark; and it starts absorbing reactive current ($Q_{INVERTER}$) to support the system voltage (V_{SYSTEM}) when it starts swelling at about the 18 seconds time-mark. The reactive power injection and absorption has, in this case, minor effects on active power for the event duration.

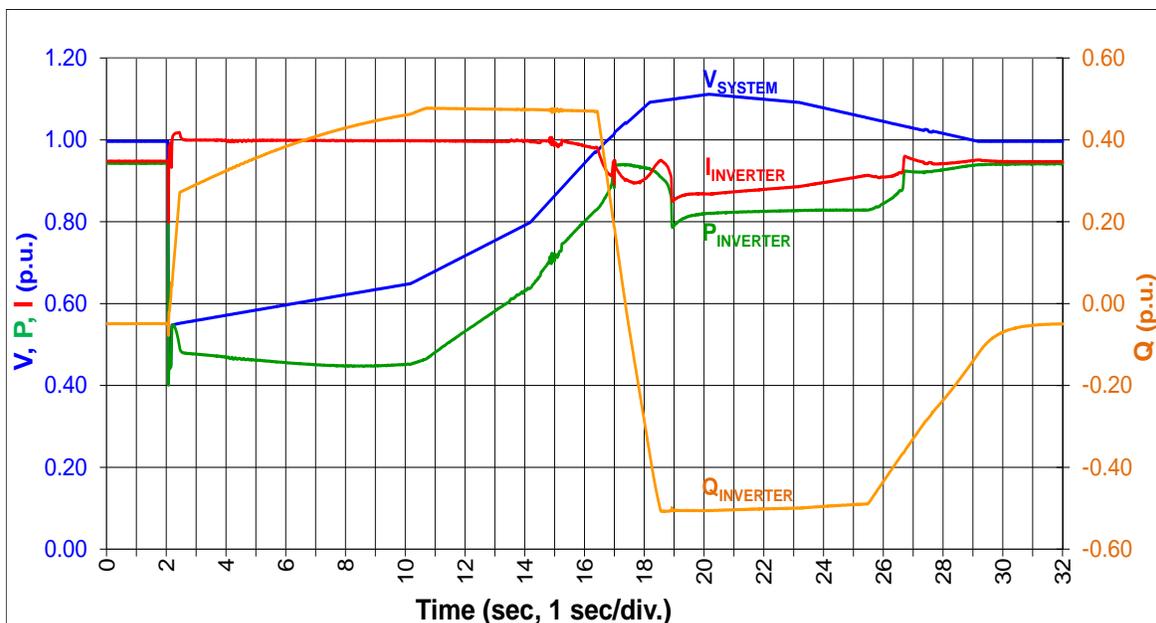


Figure 1. Smart inverter Voltage Ride-Through performance.

1.2 Frequency Ride-Through and Frequency-Watt

The national DER standard IEEE 1547-2003 only provides maximum frequency trip time ranges. The new IEEE 1547-2018 includes both mandatory frequency ride-through and disconnection time ranges during grid frequency events. Furthermore, it requires the DER to provide additional support with governor function to decrease active power to stabilize grid over-frequencies. The smart inverters could have the ability to increase real power to support low frequencies if active power reserve (e.g., from pre-curtailment or from energy storage) is available. Figure 2 shows a smart solar PV inverter performance during an over-frequency event. Notice that the smart inverter rides through the over-frequency event (f_{SYSTEM}).

Furthermore, it starts supporting the electric grid when the system frequency (f_{SYSTEM}) starts increasing at the 3.5 seconds time-mark by reducing the smart inverter active power ($P_{INVERTER}$).

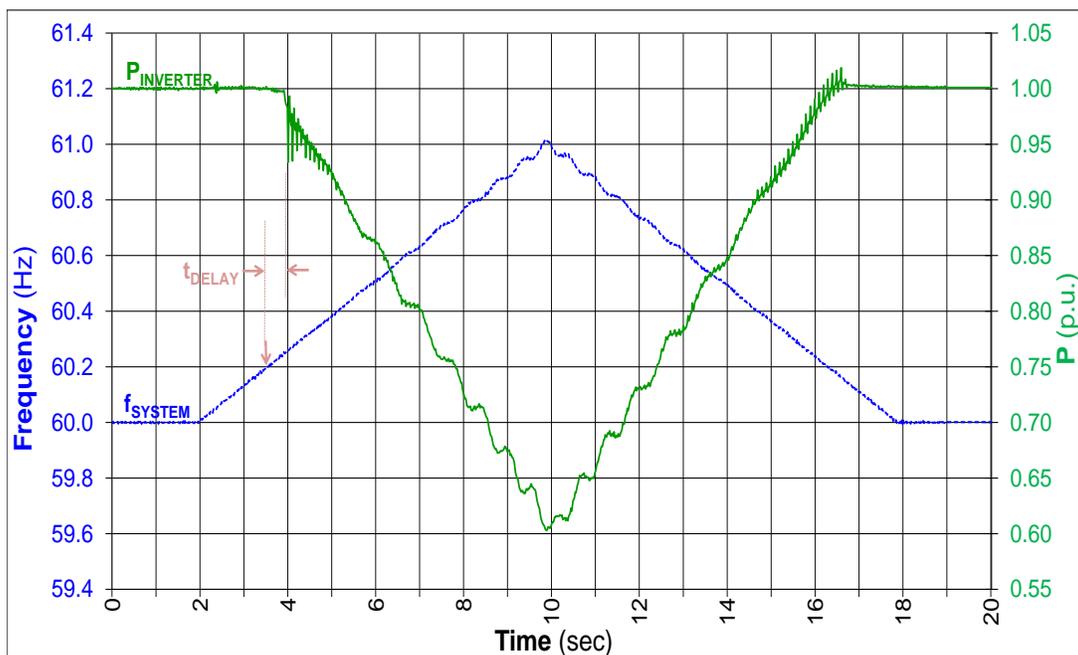


Figure 2. Smart inverter Frequency Ride-Through performance.

1.3 Voltage Support

The old standard IEEE 1547-2003 does not allow for voltage support from DER. The new IEEE 1547-2018 requires and specifies voltage support for DER to support the local grid voltage. This support is achieved by adjusting either or both reactive power (Q, VARs) and active power (P, WATTS).

1.3.1 Volt/VAr

The new IEEE 1547-2018 requires steady state voltage support by means of supplying or absorbing reactive power during under-voltage and over-voltage conditions near the normal operating voltage value, respectively. This can support and stabilize the local voltage. Figure 3 shows a smart inverter reactive voltage support during Various under-voltages. It shows how the smart inverter starts supporting the system voltage (V_{SYSTEM}) when the voltage starts decreasing at the 5 seconds time-mark by injecting reactive power ($Q_{INVERTER}$). Notice that when the Volt/VAr is OFF ($Q_{VOLT/VAR OFF}$, blue plot) the system voltage decreases much lower than when the Volt/VAr is ON ($Q_{VOLT/VAR ON}$, green plot).

Figure 4 below shows a smart inverter reactive voltage support during grid over-voltages. The smart inverter starts supporting the system voltage (V_{SYSTEM}) when the voltage starts decreasing at the 5 seconds time-mark by absorbing reactive power ($Q_{INVERTER}$). Notice that when the Volt/VAr is OFF ($Q_{VOLT/VAR OFF}$) the system voltage increases much higher than when the Volt/VAr is ON ($Q_{VOLT/VAR ON}$).

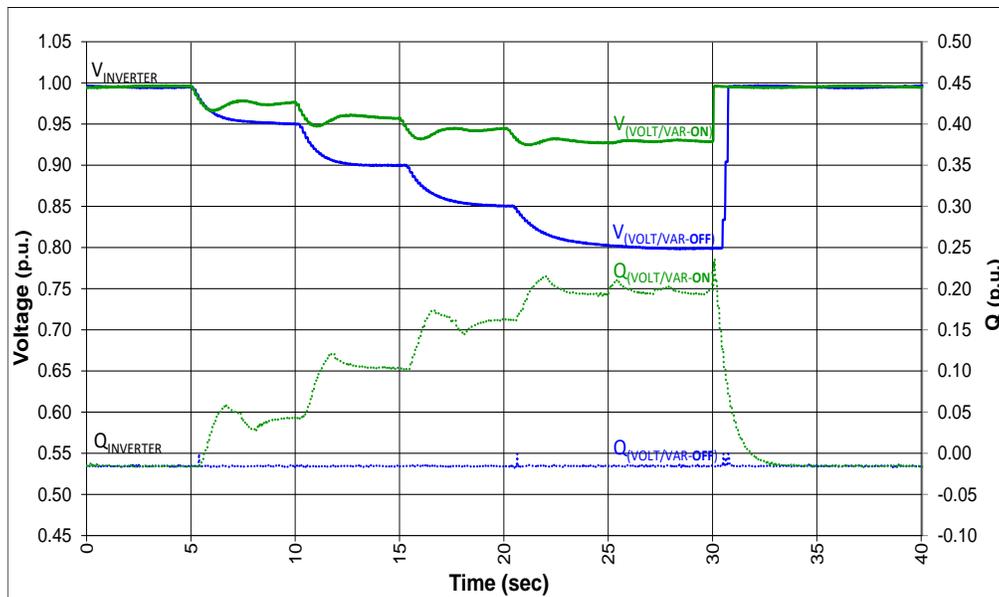


Figure 3. Smart inverter Volt/VAr performance during an under-voltage event.

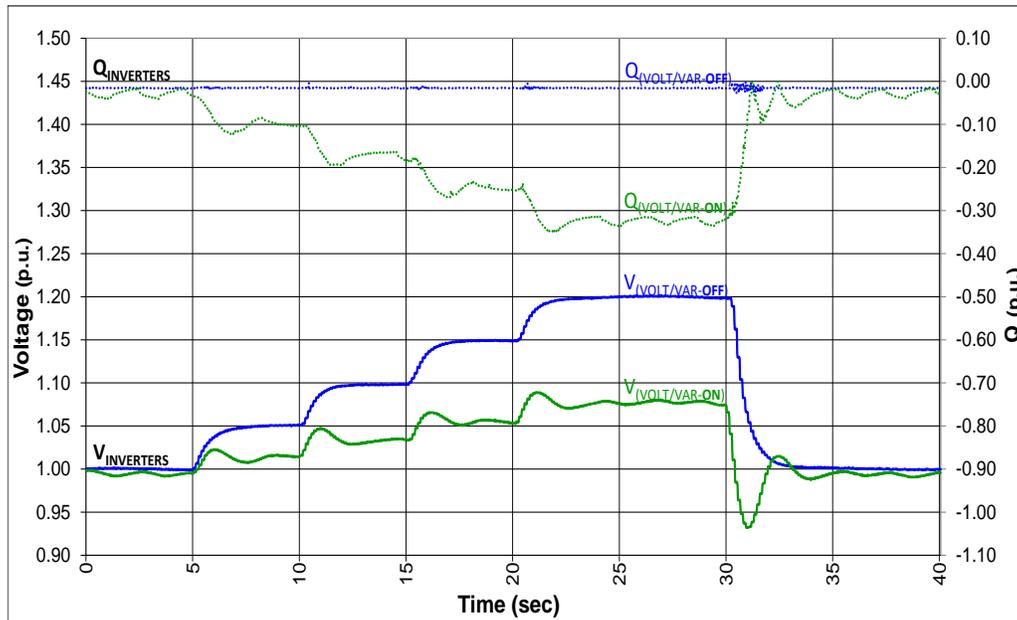


Figure 4. Smart inverter Volt/VAr performance during an over-voltage event.

1.3.2 Volt/Watt

The Volt/Watt feature allows solar PV inverters to decrease their output active power during over-voltage conditions. This feature can be used in parallel with Volt/VAr (especially starting at the tail end of Volt/VAr) to further prevent over-voltages. If spin reserve is available, solar PV inverters could be used to support the voltage during under-voltage conditions by injecting real power in the electric grid.

Figure 5 below shows a smart inverter active voltage support during both under-voltage and over-voltages.

DURING UNDER-VOLTAGE: The smart solar PV inverter starts supporting the system under-voltage (V_{SYSTEM}) at its set point of 103% voltage (60 seconds time-mark) by injecting reactive power (Q) up to 1200VARs that is the set power factor of 0.91PF. The active power (P) did not provide support during the under-voltage since it is at its maximum output (2.7 kW). The under-voltage support ends at the 225 seconds time-mark.

DURING OVER-VOLTAGE: The smart solar PV inverter starts supporting the system over-voltage (V_{SYSTEM}) at 103% voltage (320 seconds time-mark) with both active power (P) and reactive power (Q). The smart inverter absorbs reactive power (Q) up to its maximum (1.2kVAR) which is its set power factor of 0.91 PF. At the same time-mark (320 seconds), the active power (P) starts decreasing and reaches ZERO at 109% voltage. The smart inverter was set with volt/watt setpoints of 104%–109%, meaning that the smart inverter will start reducing active power at 104% and reach ZERO active power when the voltage reaches 109%. In this case, the slope is a 20% active power reduction per 1% voltage increment.

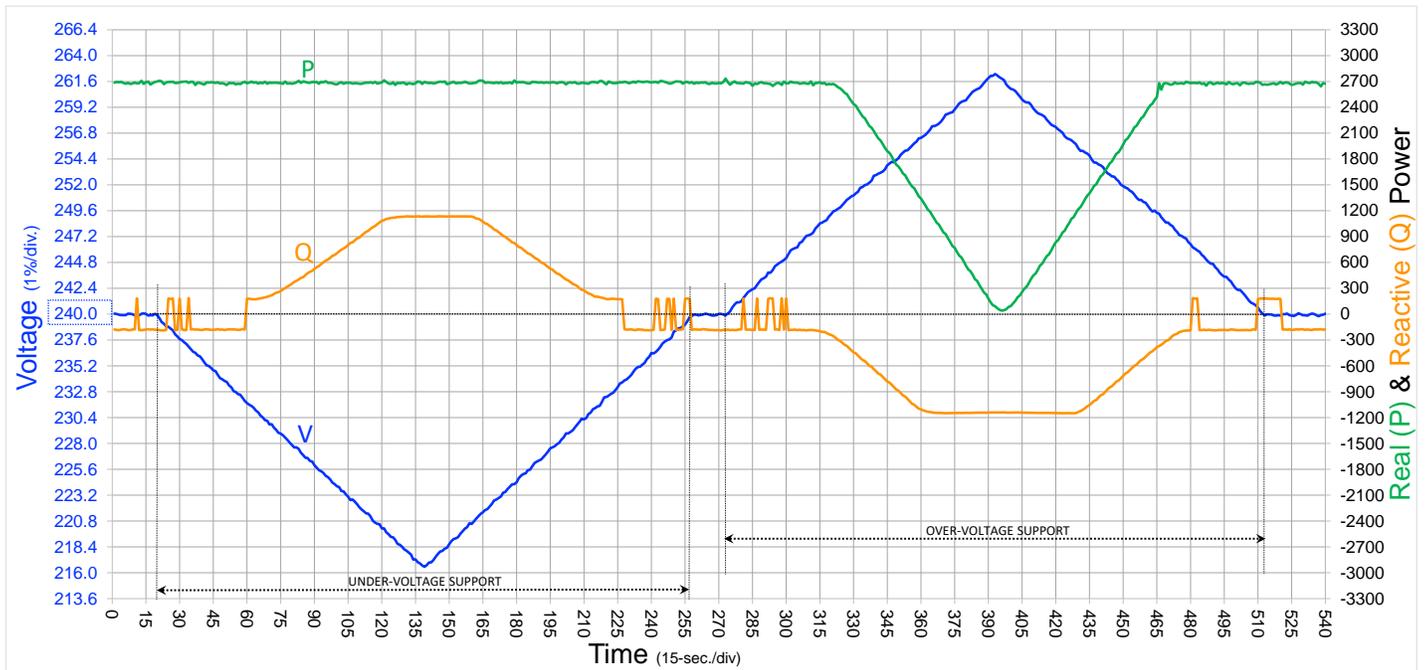


Figure 5. Smart inverter Volt/Watt performance during an under-voltage and over-voltage events.

1.4 Start-Up Ramp Rate

The national standard IEEE 1547-2003 does not provide ramp rate requirements for DER. Uncontrolled ramp rates on DER could potentially create over-voltages due to the electric current inrush specially during restarting. The new proposed IEEE 1547-2018 includes ramp rate settings so that utilities could choose an appropriate ramp rate of all or specific DER installations. Figure 6 shows a smart solar PV inverter performance during start-up. Notice that the smart inverter starts generating electric current (I_{OUT}) at the 10 seconds time-mark in a ramp-up fashion and takes 10 seconds to go full output.

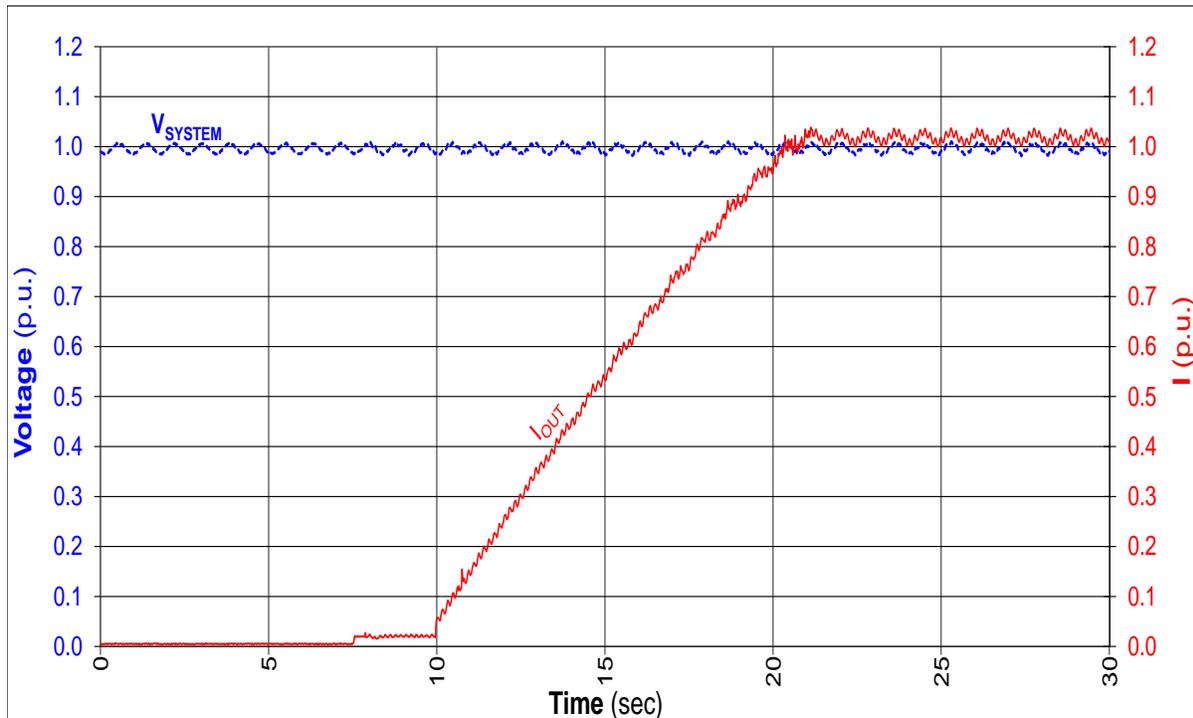


Figure 6. Smart inverter ramp-up rate performance during start-up.

1.5 Power Quality

Interconnections can have an impact on many aspects of power quality and IEEE 1547-2018 provides guidance on many of these aspects. DER quantity, density, and size of interconnections can all impact power quality. Because of the breadth of power quality, Section 2 of this white paper deals with power quality in some depth.

1.6 Fault and Unintentional Islanding

IEEE 1547-2018 requires that DERs cease to energize the Area Electric Power System (EPS) during faults on the circuit to which the DER is connected. The DER voltage and frequency ride-through requirements apply during a fault condition. This issue is discussed in more detail in Appendix B.

IEEE 1547-2018 requires that DERs detect and cease to energize an unintentional island within two seconds of formation, or before the first reclose interval of the device that formed the island, if applicable. These requirements are unchanged from IEEE 1547-2003. DERs must be designed such that their ride-through capabilities do not interfere with their islanding detection capabilities. Issues surrounding DER unintentional islanding detection are discussed further in Appendix B.

IEEE 1547-2018 also requires that three-phase DERs respond to a loss of a phase at the Reference Point of Applicability (RPA) by detecting the phase loss, ceasing to energize all three phases and disconnecting within two seconds. Note that one open phase is not an island for a three-phase system.



1.7 Communications

In IEEE 1547-2003 there were no requirements for the inverter or the interconnection to communicate. California in Rule 21 developed a set of communications requirements for inverters. IEEE 1547-2018 requires all DER, independent of type and size, to have communications capability and requires an open, standardized local DER communications interface to provide interoperability with utility communication systems. There are four types of information that are provided for in IEEE 1547-2018: Nameplate Information which is indicative of the as-built characteristics; Configuration Information which is indicative of the present capacity and ability of the DER to perform functions which may change based on relatively static configurations or may reflect dynamic weather or electrical conditions; Monitoring Information that provided present operating conditions of the DER, typically status data, active and reactive power output, but also what functions are active; Management Information which is used to update functional and mode settings for the DER, thus allowing new settings and the enabling/disabling of functions. In IEEE 1547-2018, the DER must support at least one of the three protocols at the local DER communication interface:

- SunSpec ModBus
- IEEE 1815 (DNP3)
- IEEE 2030.5 (SEP2).

All three of the protocols now support the four types of data specified in IEEE 1547-2018. Far more detail can be found in Appendix E.

1.8 Introduction to the Appendixes

Because of the technical nature of this topic and the material, in-depth appendixes have been added to the paper. The body of the paper provides an overview of the topics that is technically correct. The appendixes provide significantly more detail on a range of key topics. The appendixes include:

1.8.1 Appendix A — Smart Inverter Modeling

Modeling is an additional way to evaluate the potential grid impacts of interconnecting without physical testing, e.g. field testing of installed systems or certification testing of proposed equipment (UL 1741).

1.8.2 Appendix B — Fault Behavior and Islanding Detection

This appendix deals with the behavior of DER when there is a fault or islanding and explains the technical background, behavior and other characteristics in a faulted condition.

1.8.3 Appendix C — Ride-Through Capability



Recent events on the bulk power system (BPS) have illustrated the importance of ride-through capability for inverter-coupled resources connected to the transmission system as well as the distribution system. This appendix deals with the background and technical aspects of ride-through.

1.8.4 Appendix D — Distribution System Planning

This appendix covers the changes in the way that distribution planning needs to be accomplished including discussions of how interconnections impact the traditional planning process for distribution.

1.8.5 Appendix E —IEEE 1547 Communications Requirements Overview

This appendix covers how IEEE 1547 looks at communications to and from the interconnection location and the reasons that communications are required. The appendix also takes a high -level look at cyber security.

1.8.6 Appendix F — Installation, Commissioning, and Periodic Testing

This appendix looks at the requirements for installation and testing — both at commissioning and periodically.

1.8.7 Appendix G — Bibliography

A list of key documents which will provide additional background, technical basis and supporting materials.

1.9 Timeline for Roll-Out of Smart Inverters and How PUCs Are Handling the Uncertainty

Underwriters Laboratory (UL) convened a Task Group (TG) in January 2020 comprised of representatives from National Labs, Electric Utilities, Inverter Manufacturers, Interested Parties, and Nationally Recognized Testing Labs (NRTLs) to discuss and revise the existing UL 1741 Ed. 2 “Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources” (UL1741), an UL certification standard for smart inverters, in order to align it with the new IEEE 1547-2018 and IEEE 1547.1-2020 standards requirements and test procedures for distributed energy resources. The UL 1741 Ed. 2 revision is anticipated to be published coincidentally with the publication of IEEE 1547.1-2020 and the IEEE 1547-2018 Category III Ride Through Amendment in the 2nd quarter of 2020. The anticipated revisions of UL 1741 Ed. 2 are as follows:

- The existing Supplemental SA will remain within UL 1741 for the time being.
- A new Supplement SB will be added that directly refers to the IEEE 1547.1-2020 test procedures.
- For inverters capable of meeting requirements of existing codes like CA Rule 21 and HI Rule 14H, an optionality to either certify via Supplement SA or Supplement SB will be allowed, until the reference to UL 1741 Supplement SA in these existing codes has been revised.
- For inverters capable of meeting requirements of the new IEEE 1547-2018, certification via Supplement SB will be required.

Figure 7 shows the timeline for Rollout of IEEE Std 1547™-2018 Compliant DER. The revisions of UL 1741 Ed. 2 will enter effect immediately at their publication and inverter manufacturers will choose which Supplement to certify their equipment to as they deem appropriate and as the market requires.

The UL TG anticipates that inverter manufacturers must make some substantial changes, at least to firmware but possibly also to hardware, to meet all of the IEEE 1547-2018 requirements (e.g., phase jump and ROCOF ride-through). Therefore, it is expected that new products to market are not generally available until at least 18 months after publication of IEEE 1547.1 and the UL 1741-2020 revision. This means that effective dates for IEEE 1547-2018 of sooner than January 1, 2022, could create a technical barrier for non-certified inverters to interconnect to the grid. Once available, certified products will be listed on NRTLs’ websites. The below timeline summarizes the above information.

Minnesota PUC has decided under MN PUC, ORDER 159427-01, Docket E-999/CI-16-521 to monitor the progress made to bring IEEE 1547-2018 certified inverters to market and to issue a “Commission Notice” to determine the effective date at which their Technical Interconnection and Interoperability Requirements (TIIR) enter in full effect. Maryland PUC has set under RM68 an effective date of January 1, 2022, from which IEEE 1547-2018 certified inverters will be required.

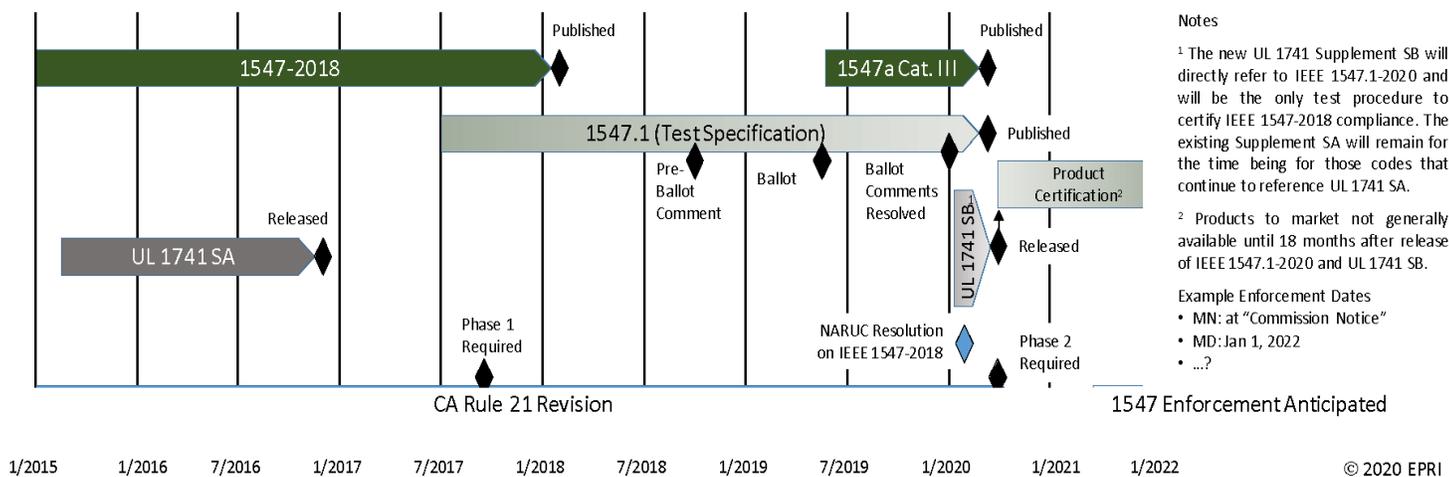


Figure 7. Timeline for Rollout of IEEE Std 1547™-2018 Compliant DER.

2.0 Smart Inverters Power Quality

2.1 Issues and Opportunities

Smart inverters increase the range of possibilities for DER’s power quality (PQ), both immunity from grid power quality issues and emissions. This means some PQ compatibility issues will be solved, however, some new incompatibilities can

be expected. Required ride-through in smart inverters likely improves DER immunity to grid disturbances. Controllable reactive power output may help to regulate end-user voltage and compensate for either high or low voltage conditions. A potential incompatibility is concentration of smart inverters employing active islanding detection. The methods can include generation of negative sequence, harmonics and continuous pulse reactive power that can add up to PQ issues. Also, inverter control malfunctions become more problematic as the grid depends on smart inverter support.

Weighing pros and cons, the expectation is that smart inverters will **improve power quality metrics** in distribution and transmission networks. There are more positive indicators than negative. For example, 1547-2018 added rapid voltage change, flicker and over-voltage limits for DER. Also, widespread monitoring, and in some cases communication, with smart inverters provides visibility to voltage levels in the distribution system. This information can support decisions and actions for maintaining voltage quality to end users. Remote control of smart inverter output, use of the Volt/VAr and Volt/Watt functions can also act to support power quality.

Key challenges to fully realize power quality benefits of smart inverters will be learning best settings, maintaining control and resolving grid-DER incompatibilities with changing grid conditions and dynamics.

2.2 Expanding PQ Role for Smart Inverters

An important determinant for the PQ role of smart inverters will be grid penetration level. A few inverters connected to a stiff grid source is not so relevant to power quality. With increasing penetration levels relevance increases. In case of 100% inverter power, such as a microgrid application, the power quality role of smart inverters increases dramatically. Without the strength of the grid to maintain voltage and frequency, the smart inverter's regulating, load-following and transient response capabilities have a larger impact on maintaining PQ. See Table 1 on the changing expectation, roles and rules of the road for DER with increasing penetration levels.

In low penetration the grid determines PQ, with increasing penetrations the DER takes on more responsibility for response to changing load. A smart inverter may be the designated lead (Isochronous or grid forming) generator in an off-grid application. For operational control in any grid, one dispatchable source needs to take the lead. Conventionally this has been the role of fossil-fuel driven synchronous generators, with inherent capability to load follow.

Inverters can play the grid forming role if they have a stable energy source, such as a battery, natural gas engine-generator, fuel cell, etc. In this case the other generators need to take a grid following role as the isochronous generator runs at fixed voltage and frequency. Therefore, any grid operation with multiple resources must have a mechanism for load sharing among resources to maintain the power balance. Droop control is commonly applied in grid following generators. The control acts to meet the reactive (by voltage droop control) and the real (by frequency droop control) power needs.

Table 1 Evolving Penetration Levels and Role of DER in the Grid (from Insignificant Resource to Microgrid)

Load Served by DER	≤ 2%	≤ 10%	≤ 30%	100%
DER Penetration Scenarios	Low-levels, stiff grid (high short circuit current at Point of Common Coupling)	Moderate-levels and relative size to grid	High-levels, hosting capacity, softer grid	Part-time island and microgrid
Grid Impact and DER's Role	Very low, not significant	Non-critical, affects local voltage	Critical to meet demand and PQ	Determines PQ of microgrid
DER Integration Objectives	Noninterference, good grid citizen	Manage impacts in distribution	DER provides grid support	Stability and energy regulation
Rules of Road	IEEE 1547-2003	Screening factors	IEEE 1547-2018	Meet demand
DER Performance Considerations	Voltage and freq. trip limits, faults synchronization	Voltage compatibility, islanding protection and recovery time	Availability, voltage regulation, power ramping coordination	Reliability, PQ, load following, capacity, reserves

Smart inverters may operate in either a grid forming or a grid following mode. Grid-following is by far the most common application for smart inverters today. With increasing penetrations in many areas of the grid relevance of smart inverter PQ is heightened.

- [Isochronous Operation](#) — refers to a regular event, in power generation, *isochronous* control mode means that the frequency (and voltage) of the electricity generated is independently held constant, and there is zero generator droop.
- [Droop Control Mode](#) — strategy commonly applied to generators for frequency control (and occasionally voltage control) to allow parallel generator operation (e.g., load sharing).
- [For Grid-Following Operation](#) — all the generator and energy storage resources operate in droop control mode and the utility is the isochronous generator reference.
- [For Grid-Forming or Microgrid Operation](#) — one generator is designated to run in isochronous mode and all others follow in droop mode. Larger and higher inertia prime movers are normally the reference machine. PV inverters are nearly always operating in droop mode. Battery inverters may operate either way when generating.

2.3 Power Quality Performance Requirements

The expectation is that smart inverters will play a larger role, and, overall, improve power quality. Along this line of thinking the new 1547 expanded, and further defined several power quality requirements. These requirements apply to individual DER system performance and include both immunity and emission limits for compatibility with a typical grid connection. Emissions are covered in Section 7 of the new standard. See Table 2 comparing the 2003 and the 2018 IEEE 1547 requirements in Section 7.

2.4 Smart Inverters Emissions

Table 2 Comparison of PQ Emission Limits from IEEE 1547 2003 to 2018

1547 PQ Emissions Section	2003 PQ ¹	2018 PQ ¹ Requirements
DC Injection Limit	.5% current	No change
Synchronization	±5% ΔV at PCC	Δf, ΔV, ΔΦ ranges at PCC
RVC	None	New ΔV MV-3%, LV-5%
Flicker	Shall not cause	New Pst < .35, Plt < .25
Harmonic Current	<5% TDD	<5% TRD, Relaxed Evens ²
Harmonic Voltage	None	None
OV Temporary	No disturbing GFO	New ≤138% V _{L-G} or V _{L-L} ³ for GFO&LRO ¹
OV Cumulative Instantaneous	None	New 2pu@1.5ms/1.4pu@16ms

Table Notes:

1. IEEE 1547 addresses limits at interconnection (PCC).
2. Compared to IEEE 519-2014 some small differences, including TRD instead of TDD and relaxation of higher even harmonics limits.
3. IEEE/ANSI C62.92-6 addresses effective grounding for inverters.

Table Acronyms:

PCC=Point of Common Coupling, TDD=Total Demand Distortion, TRD=Total Rated Distortion, RVC=Rapid Voltage Change, GFO=Ground Fault Over-voltage, ΔV=change in voltage, pu=times rated voltage

Specific changes in the power quality-related emissions limits effective for smart inverters in 2018 are the following:

- 1) [Entering Service](#) — Ramping in power and limitation on voltage changes were added by IEEE 1547-2018. These limits depend on the rating of the DER. The new standard also specifies criterion on EPS voltage and frequency that must be present before entering service. Depending on a size criterion, DER performance when entering service requires adjustable time delay, randomized time delay and/or linear ramping of power.
- 2) [Rapid Voltage Change](#) — A new requirement for both MV and LV connections is defined in terms of a one-time voltage not to exceed 3% in a one second period. RVC is recognized to depend on the relative size of the DER at the PCC and is therefore not listed to be type tested. The draft 1547 states “RVC limits shall apply to sudden changes from events such as frequent energization of transformers, switching capacitors or from step output Variations caused by generator miss-operation. These RVC limits shall not apply to infrequent events such as switching, unplanned tripping, or transformer energization related to commissioning, fault restoration, or maintenance.”

- 3) [Flicker](#) — Contribution limits are specified for DER. These limits for Pst (short-term, 10-minute measure) and Plt (long-term, 2-hour) were chosen after significant debate and consideration. Also specified is not-to-exceed a 95% probability value based on at least one week of measurements. The draft refers to assessment and measurement methods for flicker defined in IEEE Standard 1453™ and IEC TR 61000-3-7. Equipment other than a DER can mitigate the DER induced flicker. Also, exceptions can be made by the Area EPS operator with consideration of other flicker sources and it is noted that this requirement is not intended to address issues associated with slow voltage Variations. These can be caused by cloud shadow passage, wind speed changes, etc.
- 4) [Harmonic Current Distortion](#) — The limits did not change much compared to the 2003 standard and the limits in IEEE 519-2014. Even harmonics limits are slightly relaxed, except 2nd harmonic. A Total Rated Distortion (TRD) is defined to distinguish DER from demand. The formula includes all harmonic components. Measurements of harmonic and inter-harmonic values are as defined in IEEE Standard 519™.
- 5) [Over-voltage Contribution](#) — DER over-voltage contributions, such as ground fault and load rejection, are addressed. Instantaneous, fundamental frequency and cumulative over-voltages are limited. If area EPS is designed to be “effectively grounded,” then Line to Ground and Line to Line fundamental frequency voltages are limited to 138%, with reference to ANSI C62.92.1, cumulative is limited to 2pu up to 1.6ms duration, 1.7pu up to 3ms, 1.4pu up to 16ms and to 1.3pu up to 166ms.

2.5 Smart Inverters Immunity

The interconnection integrity (immunity and withstand) requirements are about the same as IEEE 1547-2003. New standards are referenced, and more compatibility levels included. Related to Electro-Magnetic Compatibility (EMC) the DER must be compliant with IEEE Standard C37.90.2™, IEC 61000-4-3, or other applicable industry standards. Electric field strength levels of 30 V/m and below should not cause change in state, mis-operation, or affect DER performance.

Surge with-stand performance is to be compliant with IEEE Std C62.45™ “IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000 V and less) AC Power Circuits” or IEC 61000-4-5 “International Electrotechnical Commission's international standard on surge immunity”, or other applicable industry standards. For DER rated less than 1000 V, surge with-stand capability needs to meet level(s) in IEEE Std C62.41.2™, or equivalent. Immunity of DER signal and control circuits is to meet IEEE Standard C37.90.1™, or other recognized industry standards. The DER paralleling and isolation device must be able to withstand 220% of rated voltage for an indefinite duration. This applies for DER able to produce a voltage (operate in a standalone mode) and without a grid connection.

2.6 Setting PQ Expectations with Smart Inverters

Nearly all issues regarding individual DER's PQ behavior are covered well by the new 1547 standard and are verified as part of the certification process. However, IEEE 1547 requirements such as rapid voltage change, and flicker limits depend on the grid strength at the PCC. They can't be certified by individual inverter testing. Similarly, the question “Will back feed cause voltage regulation issues?” depends on grid connection characteristics. The potential for incompatibilities with native loads affecting voltage quality depends on site-specific characteristics. These are examples of power quality integration concerns brought up by IEEE 1547 but addressed during screening and interconnection studies.



Screening is aimed to fast track interconnection not expected to cause any grid issues. Failing screening leads to a more detailed study. One of the first screens confirms if DER are certified and thus passed all PQ tests. Screening further addresses PQ by considering aggregate DER characteristics such as unbalance for single-phase inverters or using a relative size screen (or a stiffness ratio, typically the grid source short circuit capacity at the PCC, $S_{SC} / \text{kVA rating of DER, } S_{DER} > 25$). Failing first-level screens leads to an option for supplemental screening or studies. In this case smart inverter setting options may offer built in mitigations that can alleviate specific issues.

Overall, smart inverters are expected to contribute to PQ compatibility with DER. IEEE 1547 required performance, integration screening and grid support address many anticipated power quality needs. Remaining challenges will stem from unexpected interactions. With more DER on more feeders, and more setting options there is a likelihood of incompatibles. Power quality issues are not expected to be common or necessarily significant, however we do expect some new problems and a learning curve from deployment. Table 3 provides a summary with some educated speculations on how different power quality parameters may be affected by DER with smart inverters.

2.7 Realizing Full PQ Value in Smart Inverters

Beyond meeting PQ requirements for certification, smart inverters can do more to support and maintain voltage quality in the grid. The process, from accommodating to integrating DER into the grid, will be critical to maintaining power quality. Certification, screening, coordination of normal and abnormal operations and follow up after installation will all be important. Nevertheless, even best efforts in setting requirements and in making interconnection decisions, will not prevent all unanticipated incompatibilities.

IEEE 1453.1-2012, "IEEE Guide – Adoption of IEC 61000-3-7:2008, Electromagnetic Compatibility (EMC) – Limits – Assessment of Emission Limit for the Connection of Fluctuating Installations to MV, HV and EHV Power Systems

The following steps are recommended to get the most PQ value from smart inverters:

- Certify to meet PQ requirements of new IEEE 1547.
- Screen for PQ compatibility at the PCC and on the feeder.
- Coordinate ride-through settings between distribution protection and grid operator.

From 1547 draft 7.2.2 is not intended to address issues associated with slow voltage Variations, which can be caused by cloud shadow passage, wind speed changes, etc.

- Coordinate ride-through settings between distribution protection and grid operator.
- Customize reactive power support settings to help maintain voltage quality.
- Recognize that changing conditions in the grid may precipitate incompatibilities.
- Do not rely on communication to maintain power quality.
- Do provide power quality monitors for relatively large sites that may be problematic.

On-going deployment of DER is expected to increase the need for power quality investigations and problem solving. The challenge may be compared to 1980s and 90s deployment of power electronics in appliances and in process industries. This changed requirements and expectations for grid power quality. Now the grid environment is again changing because of inverter connected DER and perhaps more than ever before. Prior experiences and learning are expected to serve the utility industry well in new efforts to establish compatibility between end-use equipment, DER and the power grid. More information on the impacts of smart inverters on the system power quality can be found in [1]–[9].

Table 3 Summary of Power Quality Considerations with Smart Inverters

Smart Inverters are likely to help
<ul style="list-style-type: none"> • Entering Service – expect better ramp-rate and frequency control, as well as adjustable or randomized time delays for restoration of DER.
<ul style="list-style-type: none"> • Immunity to voltage sags – will improve with new ride-through requirements and depending on the location and choice of settings may reduce the number of trips by up to 80% based on EPRI’s transmission and distribution power quality environment data.
<ul style="list-style-type: none"> • Avoiding high or low voltage at PCC – Volt/VAr and other reactive power support modes improve voltage regulation at the PCC and when coordinated with other voltage control can help smooth normal feeder voltage Variations caused by distribution generation and load.
<ul style="list-style-type: none"> • Limits on cumulative over-voltage – New over-voltage limits are expected to reduce load rejection over-voltage (LRO), improving inverter response to sudden loss of load.
Smart Inverters may lead to new incompatibilities
<ul style="list-style-type: none"> • Flicker – incidents may increase where reactive power control becomes unstable, active anti-islanding modulates reactive power or related reactive power control failure. DER contribution to flicker levels is measurable but relatively small and may be insignificant compared to high fluctuation loads. Even PV output changes with moving clouds are relatively slow and become slower with geographic diversity. Other factors that limit DER capacity tend to make PV flicker a non-issue with stiffness ratio greater than 5.
<ul style="list-style-type: none"> • Harmonic Current Distortion – perception of increasing with higher harmonic content during low levels of real power output (e.g., circulating VARs in a pf correction mode) or when a wider range of inverter output impedance finds resonant points with the grid. Higher order harmonics, up to 20 kHz from inverter switching, sometimes appear as resonances in special circumstances. Low-order grid voltage distortion or unstable DER controls in a weak grid may be contributing factors. Prediction of these issues by modeling is difficult.
<ul style="list-style-type: none"> • Communication interference – when communication is relied on to manage smart inverter performance, there may be vulnerabilities, lack of immunity and failures to communicate.
Smart Inverters are not likely to affect
<ul style="list-style-type: none"> • Over-voltage contribution – DER-related over-voltage is expected to increase in distribution because of increased deployment. Mitigating factors include onboard trip limits and active anti-islanding response. However, back feed into a ground fault (GFO) may require additional protection if not limited by grounded load.
<ul style="list-style-type: none"> • Rapid Voltage Change – the main issue is unnecessary transformer energization should be avoided. Otherwise fast voltage Variations are not expected if DER is operating as intended. Transformer inrush when connected to the grid can be problematic. Such connections should be infrequent. A new RVC requirement in 1547 addresses fast voltage changes common to inrush.
<ul style="list-style-type: none"> • Immunity to EMI and voltage surges – the inverter power stage immunity should be about the same. Communication interference possibilities more likely increase.

2.8 Future Needs of Smart Inverters

Smart inverters may be improved with features such as the following:

- Dynamic Voltage Support during abnormal voltage conditions: this function was intentionally not specified in IEEE 1547-2018 as it can provide opportunities for the bulk power system along with challenges for the distribution grid and its performance and use need further investigation.
- Dynamic Harmonics Cancellation: smart inverters could be designed to automatically adjust its settings to find an optimal voltage total harmonist (V_{THD}) at its terminals during steady state condition.
- Reactive power support during night times: future inverters could be designed to provide voltage support even when there is no input energy.

Given these future possibilities for smart inverters, the sponsor of IEEE 1547-2018, the IEEE SA’s Standards Coordinating Committee 21 (Fuel Cells, Photovoltaics, Dispersed Generation, and Energy Storage) has developed a roadmap for the revision of the P1547.x series of standards as shown in Figure 8 below. The criteria for future revisions of these standards include:

- IEEE Required timing (10 years)
- Need for any immediate or emergency updates or amendments
- Review of wish list for a standard
- Market adoption conditions / regulatory reference projects
- Availability of SMEs, key participants or leaders
- Related efforts, including IEEE SA projects (standards, recommended practices, guides).

Standard	Topic	Expires (10 yrs)	2018	2019	2020	2021	2022	2023	2024	2025	2026
P1547	Base Std	2028	Revised	Active Working Group	Amended	PAR: Std	Future Working Group	Revision?			
P1547.1	Test Std	2030			Revised		PAR: Std	Future Working Group	Revision?		
P1547.2	Application Guide	2018	PAR: G			Expected Revision		PAR: RP	Future Working Group	Revision?	
P1547.3	Cyber Security	2018 – parts in 1547-2018		PAR: G			Expected Revision		PAR: RP	Future Working Group	Revision?
P1547.4	Intentional Islands	2021				Expires					
P1547.5	DER > 10 MVA	Withdrawn – now partly in P2800									
P1547.6	Secondary Networks	2021 – now in 1547-2018				Expires					
P1547.7	Impact Studies	2023						Expires			
P1547.8	Recommended Practice	Inactive (Included in Revised 1547)									
P1547.9	Storage + V2G	New Std		PAR: G		Expected Completion		PAR: RP	Future Working Group	Revision?	

Legend: Active Working Group (orange), PAR Development (yellow), Future Working Group (green)

Project types: Std – Standard; RP – Recommended Practice; G – Guide

Figure 8. DER Modeling Framework



3.0 Acknowledgments

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Appendix A — Smart Inverter Modeling

The functions of smart inverters could cause impact to power system steady state and transient operation. Software modeling tools are used to evaluate these impacts. Different types of software modeling tools can represent smart inverter functionality differently, typically are specific to distribution or transmission application, and each have associated advantages and disadvantages. These different software modeling tools and their applications are detailed in this appendix.

Modeling and power system simulation is how interconnection impacts and mitigation are evaluated for most transmission connected resources. However, that is not currently the case for distribution connected resources, including smart inverter connected resources.

The state of modeling tools has improved vastly over the last decade. While the state of modeling tools has improved vastly over the last decade, there are limitations in their present capabilities to fully model and simulate the full range of smart inverter performance requirements in revised IEEE 1547-2018. While steady state modeling can cover the basic functions, dynamic stability modeling allows for full modeling-based evaluation of a proposed smart inverter-based resource under transient power system conditions, and for evaluation of ride-through characteristics. The general System Impact Study procedures used for decades for transmission interconnections can be used at the distribution level. However, the software tools may not. Specifically, simplified single line positive sequence models appropriate for transmission studies may not be adequately detailed for distribution, where full three phase representation in modeling and simulation may be needed. While there are abundant simulation software tools for 3-phase load flow, there is a need for development of 3-phase dynamic stability modules to complement these load flow simulation products.

A.1 Modeling Purpose

The software model types in general are used in a Variety of power system studies that are performed for power system planning and operations function. For example, these models are used in studies that support resource interconnection review and approval and are used for grid capacity expansion planning. The modeling of smart inverters in this context is usually associated with resources, e.g. PV solar and energy storage that are connected to the grid through inverters and/or converters. The attributes of smart inverters are very relevant in context of both interconnection studies, where impacts from a proposed resource are evaluated, and capacity planning studies that compare alternatives to mitigate grid constraints defined by thermal loading, voltage limits, or stability limits. In each of these cases, smart inverters have performance capabilities that must be represented (i.e., modeled) to ensure that:

- 1) Any negative impacts are mitigated, and
- 2) Any grid supportive capabilities are fully leveraged for the benefits that can be derived from smart inverters.

Software models are typically simplified representations of actual equipment functionality. Ensuring software models accurately represent actual equipment functionality is critical for simulations to produce useful results. Model validation from equipment and system testing can help assess and improve the accuracy of software models. Hardware-in-the-Loop (HIL) can also be used for model validation. Two common forms of HIL are Power HIL and Controller HIL. HIL testing can

be used to simulate conditions that could not be easily tested otherwise (e.g., system faults), and have lower risk as fewer components are involved. However, note that the more accurately the test conditions simulate expected field conditions, the better the results can be used to validate model performance.

A.2 Phasor Domain Modeling of Smart Inverters

Phasor domain tools are most commonly used to model transmission systems, where aggregated smart inverter installations are represented in BPS planning studies. Because of their application on transmission systems, typically the three-phase systems are modeled as positive-sequence equivalents and furthermore are assumed to be in a balanced form. Examples of phasor domain commercial software modeling tools include PSS/E, PSLF, and PowerWorld. The NERC System Planning Impacts from DERs Working Group (SPIDERWG), the WECC Renewable Energy Modeling Task Force (REMTF), and industry have been developing recommended practices and modeling capabilities for aggregate DER modeling for BPS planning studies [62]. The modeling framework is depicted in Figure 9. Aggregate DER is often being separated into retail-scale DER (R-DER) and utility-scale DER (U-DER) for the purposes of modeling and can be represented as either a part of the load record or as a generator in the base case. New dynamic models such as the aggregate or equivalent DER_A dynamic model have the capability to represent many of the advanced features of new smart inverter installations. These dynamic models can be attached to the DER modeled as a generator or as a component of the load record as well.

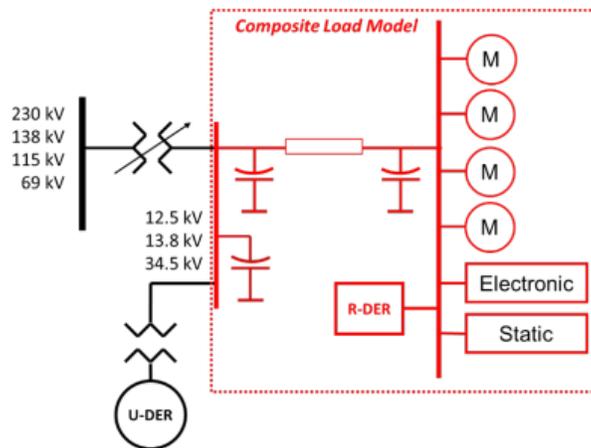


Figure 9. DER Modeling Framework.

A.2.1 Reactive Power Management During Steady State Operation

In a steady state setup, smart inverter-based resources can be modeled as a generator. The generator control mode can be set to operate the generator at voltage control mode, constant power factor mode, or fixed reactive power mode. These control modes can provide reactive power management functionality comparable to those offered by smart inverters. Industry organizations, such as WECC REMTF, work to ensure standard models represent these functions.



A.2.2 Steady State Fault Current Contributions

In conventional phasor domain analysis, short-circuit fault contribution levels of generators are analyzed assuming the machine pre-fault operating voltage, terminal voltage during a fault, and impedance drive the fault current output of the machine. This procedure does not reflect the appropriate current magnitude and angle of fault current contribution from inverters, particularly for faults that are not electrically close. Inverters are modeled approximately as constant-current or constant power sources, with fault current contribution typically limited to about 1.2 pu. Some short-circuit analysis software tools now provide the capability of modeling inverters at voltage-controlled current sources.

Further research is needed to understand the fault current contribution at the transmission to distribution interface from aggregate amounts of DER dispersed throughout a distribution system with other end-use loads. Advanced tools such as transmission and distribution co-simulation can be used to explore this unanswered research question.

A.2.3 Dynamic Response to System Events

Common transmission dynamic simulation software tools (e.g., PSS/E, PSLF, PowerWorld) provide models specifically designed to represent the dynamic response of inverter DER to system events, including smart-inverter functionality. Inverter generation should never be modeled by synchronous generator models in dynamic simulations. The generic inverter DER models include voltage and frequency trip settings, as well as real and reactive power controls (e.g., voltage regulation and governor functionalities). The models will continue operation during disturbances up to the specified trip or momentary cessation threshold; thus voltage and frequency ride-through is appropriately modeled.

For modeling of multiple smart inverters on the distribution grid, aggregated DER models like the generic DER_A model are now available in the common transmission analysis software tools. The characteristics of the generic inverter DER models are based on the functions specified in IEEE 1547-2018 and the input parameters are in most cases sufficient to represent the inverters for dynamic simulations. The DER_A model can also represent dynamic voltage support even though that function is not required by IEEE 1547-2018; this feature can be used to adequately represent VAr support during under-voltages and over-voltages of solar PV inverters.

User-defined models are generally not necessary, unless specific internal components or controls are known to prevent the inverter DER from riding through system events — a performance that would often lead to non-compliance with existing interconnection standards like IEEE 1547-2018.

Inverter controls also exhibit behaviors that are outside of the frequency range appropriately modeled by phasor-domain dynamic simulation programs. Also, positive-sequence phasor-domain dynamic simulation tools are not capable of correctly modeling inverter DER response to unbalanced faults. Evaluation of high-frequency performance characteristics and issues, such as inverter current regulator or phase-lock loop stability, or situations involving severe phase imbalance, can require electromagnetic transient (EMT-type) simulation studies.



A.2.4 Reactive Power Management During Faults or System Reconfiguration

System reconfiguration is when network switches are opened or closed in the system. Closing switches can interconnect additional circuit segments or parallel circuits together. Opening switches can disconnect circuit segments.

In dynamic simulations using phasor-domain tools, smart inverter-based generation includes controls, which can be represented in the software tool, for example by using the generic DER_A model mentioned above. These controls can adjust reactive and active power output. The smart inverter controller behavior during a fault can be modeled in the controls. Consequently, the inverter reactive power output during the event can be represented with the simulation.

While many smart inverter functions can be represented by user-defined models, many system operators have required that generic models are used for system-wide simulations. While these generic models may sufficiently represent typical slow-dynamic behaviors of the inverter controls adequately, fast acting inverter control performance may not match measured data that will vary by inverter and manufacturer. Reducing these uncertainties in inverter dynamic response during grid events can be achieved by new specifications, like those for dynamic voltage support, in future revisions of IEEE 1547.

A.2.5 Limitations of Phasor Domain Modeling of Smart Inverters

One limitation of phasor domain smart inverter modeling is the inability to consider unbalanced conditions or fast dynamics that occur during grid disturbances. For example, sub-cycle events may not be accurately captured. Another limitation is accurately modeling the fault current behavior of aggregate DERs and potential current limitations of inverter-based controls during and immediately after fault events. Additionally, phasor-domain tools commonly assume a positive sequence, balanced network. This limits the ability to represent and consider unbalanced system conditions, and the response of the smart inverter system.

A.3 Electromagnetic Transient Software Modeling of Smart Inverters

Using an Electromagnetic Transient (EMT) software program, a detailed model of smart inverter performance can be developed. Modern EMT software modeling tools can represent key components of smart inverter systems including DC components, power electronics behavior, and controller programming. These capabilities allow EMT software modeling tools to accurately represent smart inverter functionality. Additionally, EMT software tools can represent system dynamics and transients during events to demonstrate the timing of inverter response to system events. These simulations can demonstrate the varying smart inverter behavior with respect to time as system events (e.g., faults, switching, or lightning) progress. These simulation results can be evaluated to determine if the system will respond as desired for system events (e.g., unintentional islanding is detected, or inverters ride-through events).

EMT software models are also capable of simulating unbalanced conditions in the power system by representing each phase. This allows the EMT model to consider both single- and three-phase inverter systems, as well as system unbalance conditions (e.g., phase load unbalance and unbalanced system fault conditions). A limitation of the use of EMT software



tools is that it may limit the footprint of the study since it may require high process power. Examples of EMT software tools include EMTP, ATP, and PSCAD.

A.3.1 Reactive Power Management During Steady State Operation

Smart inverter reactive power output in a Variety of control methods can be represented in electromagnetic transient modeling software. Response time and details of the reactive power implementation can also be reflected because of the capability to represent inverter and controller behavior. Reactive power output in constant power factor, voltage-reactive power (Volt/VAr), active power-reactive power (watt/VAr), and constant reactive power output modes can be represented in EMT simulations.

A.3.2 Fault Current Contributions

Smart inverter fault current contributions can also be accurately represented in EMT models. The inverter fault contributions from continued power electronic operation as well as fault contributions from passive components (e.g., filter capacitors and inductors) can be included and represented in the EMT model. These contributions often include both fundamental frequency fault contributions as well as high-frequency output from the passive filter components.

Note that EMT models can represent inverters as switched or averaged models. Some averaged models may not represent inverter faulted behavior accurately. To ensure that the EMT models are reflecting smart inverter faulted behavior accurately, model faulted inverter simulations can be compared to faulted inverter test results.

A.3.3 Ride-Through During Faults or System Reconfiguration

Ride-through for smart inverters typically refers to both frequency and voltage ride-through. Since EMT simulations include power system dynamics, the behavior of smart inverters can be closely simulated as the event progresses. EMT models can also include, via simulation of the controller, how the inverter is measuring voltage and frequency, and how it reacts to these changes. Furthermore, during system faults and reconfiguration, one significant concern is the formation of unintentional power system islands. Smart inverters, along with any other DER, are required to detect these unintentional islands and do so via a Variety of techniques. The passive and active anti-islanding methods employed in each inverter can be simulated to evaluate expected behavior during such a scenario.

A.3.4 Reactive Power Management During Faults or System Reconfiguration

During faults and system reconfiguration, if the smart inverter is riding through the event, the reactive power output of the inverter may change. During these events, voltage magnitude at the inverter terminals is likely to change. When utilizing voltage-reactive power controls, this voltage change can elicit a change in reactive power output. It is beneficial to perform a dynamic simulation of these events, as a single inverter tripping can lead to cascading tripping of other inverters.

A.3.5 Limitations of Electromagnetic Transient Software Modeling of Smart Inverters

While it is clear from the above sections that EMT software tools are capable of robustly representing the behavior of smart inverters in the power system, these tools also have some limitations. One significant limitation of electromagnetic transient software is simulation time. EMT model simulations often utilize time steps of microseconds, which can result in significant computational burden. Additionally, simulations often must be seconds in duration, as devices and controls must initialize to steady state conditions prior to simulating a change in the system. While EMT models and simulations can accurately represent detailed aspects of smart inverter behavior, they also require a detailed model, which requires significant engineering effort. Models are often not built to represent behavior in all possible conditions and may require modification for some simulations. Furthermore, EMT models are restricted by the size of the system modeled. These tools are typically applied to analyze local phenomena. Consequently, EMT software is typically not used to model large-scale systems. Finally, smart inverter systems are often integrated into the distribution system. Few North American utilities have complete EMT models of distribution systems to integrate smart inverter models into, as the modeling detail of EMT models requires significant time to build.

A.3.6 Quasi-Steady-State (QSS) Modeling of Smart Inverters

Quasi-steady-state (QSS) simulation tools are some of the most common tools used to represent the distribution system, where smart inverters are commonly integrated. QSS simulation software typically runs a network solver or power flow simulation and provides the user with phasor voltage and current information at a snapshot in time. Some QSS tools are also capable of performing dynamic or time-series simulations, but not transients. Additionally, QSS software tools are typically capable of simulating unbalanced systems. Examples of QSS tools include CYME, Synergi, and WindMil. Some QSS tools, such as DigSilent, now integrate some features (e.g., dynamic capabilities) of phasor-domain tools as well.

A.3.7 Reactive Power Management During Steady State Operation

Some modern QSS simulation tools can represent smart inverter reactive power management functions during steady state operation. This functionality is typically available through a simplified representation of the reactive power components of the smart inverter controls. For example, for Volt/VAr output the shape of the curve can be input. This allows simple representation of this functionality, without detailed parameters of the inverter controller. However, this simplified representation may not reflect the details of the control operation (e.g., timing of controls response).

A.3.8 Fault Current Contributions

Smart inverter current limitation can be reflected in many QSS simulation tools. Care must be taken to ensure that current limitation behavior is appropriate for unbalanced faults and faults that are electrically distant from the smart inverters, to ensure that simulated fault current output matches the expected levels. Additionally, the angle of the fault current output of QSS modeled smart inverters may not reflect fault current output behavior. High-frequency current output from passive filter components of smart inverters is typically not reflected by QSS simulation tools.



A.3.9 Ride-Through During Faults or System Reconfiguration

In some QSS simulation tools, a simplified ride-through simulation can be considered by including the frequency and voltage trip settings of the inverter, and assuming that the inverter continues operating if these boundaries are not violated. Since ride-through and tripping have associated timing, the inverter output may change with time. The transient and dynamic nature of ride-through scenarios make these events challenging to accurately simulate using a QSS tool. For example, the effects of switch operations and cascading inverter tripping cannot be readily represented in QSS software. Ride-through simulations using QSS tools can only provide meaningful results when simulating ride-through during long-term voltage sags or surges where the inverter reaches a steady state during the event.

A.3.10 Reactive Power Management During Faults or System Reconfiguration

As QSS simulation tools use a simplified representation of inverter reactive power controls, care should be taken to ensure that controls behavior during events accurately reflects the behavior of the smart inverter during the event. Consulting the inverter manufacturer to understand the reactive power behavior during fault or reconfiguration events and ensuring the model representation appropriately reflects the machine behavior is recommended. Additionally, many smart inverters include active anti-islanding protection mechanisms. These techniques may be challenging to simulate using QSS tools for two major reasons. First, active anti-islanding protection acts on transient and dynamic changes in the system, which cannot be readily represented in most QSS software tools. Second, active anti-islanding protection often involves proprietary techniques that are not included in the generic smart inverter modeled controls.

A.3.11 Limitations of QSS Modeling of Smart Inverters

QSS tools are commonly used to represent distribution systems, and can provide simple means to simulate smart inverter performance during events. However, some of the limitations of these tools must be considered. First, the dynamic simulations in some QSS tools may function similarly to a series of consecutive power flow solutions, which may not accurately reflect system dynamic behavior. Additionally, these tools do not include the capability to represent transient conditions. As described in the above sections, the simplified representation of inverter controls and reactive power behavior enables simplified simulation of smart inverter behavior but may require careful consideration during edge case simulations. Finally, some inverter functionality relies on terminal voltage measurements to determine behavior (e.g., voltage tripping or Volt/VAr). To accurately determine inverter terminal voltage, utilization system impedance and topology must be considered. Often distribution system models do not include modeling of utilization voltage equipment. Consequentially, behavior in actual systems may Vary from modeled behavior if utilization voltage transformers and conductors are not considered.

A.4 Co-Modeling and Co-Simulation of Transmission and Distribution Systems for DER Integration

DER proliferation in distribution grids is leading to a Variety of phenomena that may impact the transmission grid. These impacts gradually increase as the penetration of DER increases — an important insight that makes it impossible to specify

a certain penetration level above which DER should be modeled in system studies. In extreme cases, high penetration of DER may lead to reverse power flow through feeder circuit breakers and through distribution substation transformers, i.e., to backfeed into the sub-transmission and transmission grid, as shown in Figure 10. Generally increasing penetrations of DER have prompted the need to model DER as part of transmission studies. Similarly, transmission events, such as voltage sags caused by faults, may impact the operation of DER connected to the distribution grid. This growing interrelationship and dependency between both systems is blurring the traditional boundaries between transmission and distribution modeling.

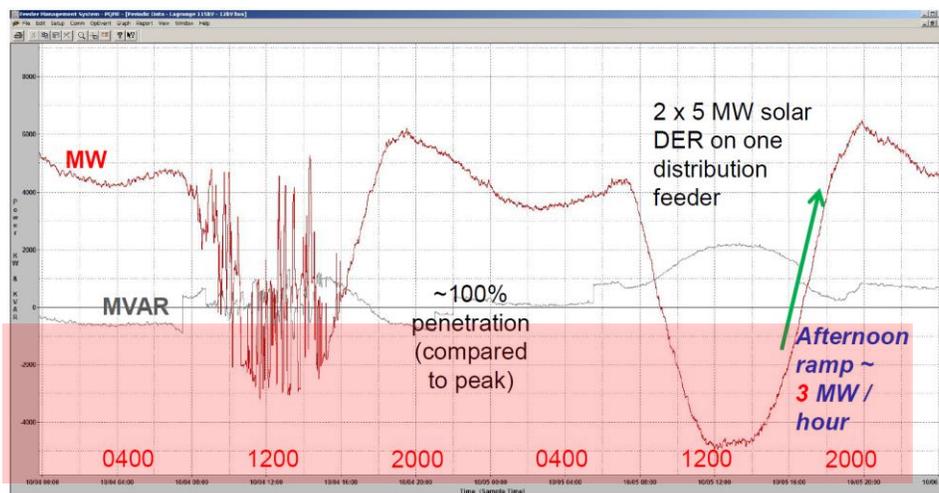


Figure 10. Example of reverse power flow through substation transformer due to high penetration of PV-DG. The region in light red indicates reverse power flow³.

In absence of field measurements that can be used to validate and improve aggregate DER models like the DER_A model for transmission planning, and for certain corner cases where positive-sequence modeling of transmission systems with equivalent representation of inverter DER may be inadequate, co-modeling and co-simulation of these systems is an increasingly important area of interest for power systems planning, analysis and operation. An overview of co-simulation platforms for transmission planning can be found in [65]. Co-modeling and co-simulation is an emerging research area and its use cases are not commonly accepted in the industry due to related challenges of implementing new practices into existing transmission planning approaches.

Co-modeling is defined as “models that are described in a unified language, and then simulated”, while co-simulation is defined as “the theory and techniques to enable global simulation of a coupled system via the composition of simulators. Each simulator is a black box mock-up of a constituent system, developed and provided by the team that is responsible

³J. E. Gajda, The North Carolina solar experience: high penetration of utility-scale DER on the distribution system, 2017 IEEE PES General Meeting, Chicago, IL.

for that system”⁴. This is conceptually described in Figure 11. Co-modeling and co-simulation are still emerging and evolving areas of research, therefore, the approaches described in this document should be regarded as preliminary solutions. Additional work and standardization are required to address existing and expected challenges to conduct this type of analyses.

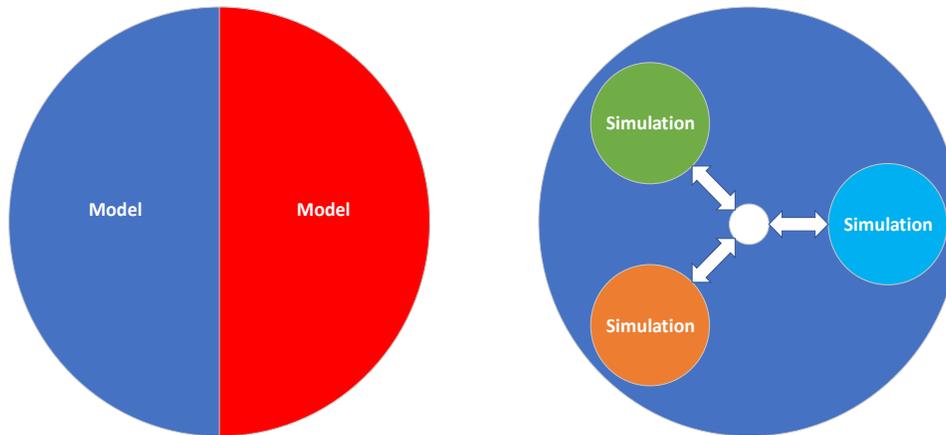


Figure 11. Conceptual description of Co-modeling (left) and co-simulation (right) of T&D systems⁵.

Some of the challenges associated to co-modeling and co-simulation of T&D systems include:

- 1) Unavailability of consolidated models: historically both systems have been largely analyzed in a decoupled fashion using different software solutions and modeling approaches (e.g., balanced positive-sequence modeling of transmission systems using software solutions specific for bulk power system analysis, and unbalanced three-phase modeling of distribution grids using distribution system analysis software).
- 2) Limited availability of software solutions with co-simulation capability: although there are some commercially available software solutions that have the capability to model integrated systems (generation, transmission, substations and distribution lines), the large majority of software solutions, including the ones commonly used by most transmission and distribution organizations, have capabilities to model only either one of these systems. This can be resolved by building integrated models, however, the level of effort and cost involved in this activity can be significant.
- 3) Size and complexity of integrated models and computational burden: transmission and distribution system models by themselves can include thousands of components (lines, transformers, generators, etc.) and can be quite complex, combining both types of models increases dimension and complexity significantly, as well as computational burden to conduct simulations, particularly time-domain and dynamic simulations. For this reason, Various simplified approaches have been proposed, and are briefly discussed in this section.
- 4) Data and model integrity issues: data and model integrity issues (e.g., erroneous or outdated equipment settings, line phasing inaccuracies, missing components, etc.) are common, particularly in distribution grid models, given

⁴B. Palmintier, HELICS for Integrated Transmission, Distribution, Communication, & Control (TDC+C) Modeling, SETO Workshop on Challenges for Distribution, May 2019, Washington, DC, <https://www.energy.gov/sites/prod/files/2019/08/f65/3.1.b.%20-%20SETO%20Modeling%20Workshop%20-%20NREL.pdf>

their complexity, evolving nature, and large dimension. Moreover, they generally only include medium-voltage lines (e.g., 13.8 kV, 12.47 kV, etc.), while secondary system models (secondary lines, service drops, etc.) are usually not available, except for secondary and spot network systems. Similarly, service transformer models are often not modeled and represented as spot loads, rather than through detailed models.

- 5) Spatial and temporal resolution and granularity of data: transmission and distribution system models also differ in terms of spatial and temporal level of detail. For instance, distribution system models are generally georeferenced, this is valuable information for system operators and distribution engineers, given the need for frequent switching during outage management and restoration, and the large number of components in the system. This is not necessarily the case in transmission system models, which are represented through electric circuit equivalents that are not georeferenced. In transmission systems real-time data with hourly and sub-hourly resolution is commonly available for most system components, while this type of data is generally only available for a small number of components (e.g., circuit breakers and reclosers) in distribution systems. Therefore, co-modeling and co-simulation of power delivery systems requires accounting for these differences to ensure coordination and consistency.

The specialized literature includes a growing number of co-modeling and co-simulation approaches for transmission and distribution systems. These approaches can be grouped in three categories:

- Co-modeling
 - Simplified models: this approach consists of developing a simplified model of the part of the grid that is not the main subject of interest of the study, but whose features and operation are recognized to be influential and worthy of more detailed consideration in the analysis. The classic example of this type of approach is, for instance, representing the bulk power system via a Thevenin equivalent in distribution system studies or modeling distribution substations as spot loads in transmission system analyses. DER proliferation has prompted interest in more detailed, but still simplified, models of transmission and distribution systems to account for the potential impacts of DER. For instance, the Western Electricity Coordinating Council (WECC) and the North American Electric Reliability Corporation (NERC) have proposed the utilization of the composite load model (CLM) to account for the impact of DER in power flow and dynamic analyses.

Figure 12 shows a comparison of the classic power flow modeling approach for distribution loads in transmission system studies and the recommended modeling that explicitly includes utility-scale DER (including respective step-up interconnection transformer and dedicated feeder) above a given installed capacity threshold, and the CLM to account for explicit representation of retail DER and the transmission-distribution transformer. NERC's Reliability Guideline – Distributed Energy Resource Modeling⁵ describes in detail the features and application of the CLM to transmission system power flow and dynamic analyses.

⁵NERC, Reliability Guideline – Distributed Energy Resource Modeling, September 2017, https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_DER_Modeling_Parameters_-_2017-08-18_-_FINAL.pdf

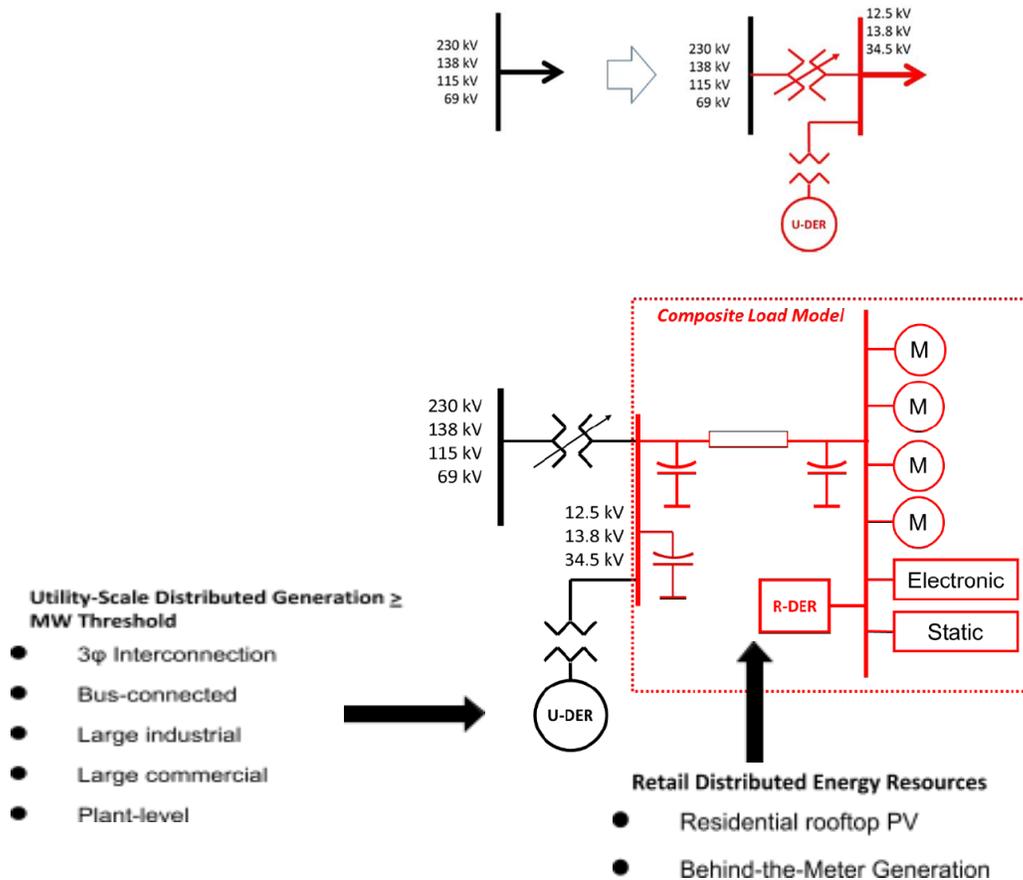


Figure 12. Load and DER representation in power flow and dynamic analyses⁶.

- **Integrated models:** this approach consists of using more detailed models of transmission and distribution systems, such as those used when analyzing either system individually, to develop a single power system model. This type of modeling relies on specialized software solutions with the capability to model transmission and distribution grids. Figure 13 shows an example of an integrated model with explicit representation of transmission, sub-transmission, and distribution (medium and low voltage) systems.
- **Co-simulation:** this approach relies on separate simultaneous simulation of transmission and distribution systems, where both systems are modeled and solved in separate software solutions and exchange boundary conditions to ensure consistency (e.g., time synchronization). Figure 14 shows an example of a co-simulation framework for analysis of transmission and distribution systems, from ISO to appliance level.

⁶North American Transmission Forum, NATF Reference Document: Distributed Energy Resource Modeling and Study Practices, <https://www.natf.net/docs/natf/documents/resources/planning-and-modeling/natf-reference---der-modeling-and-study-practices--open.pdf>

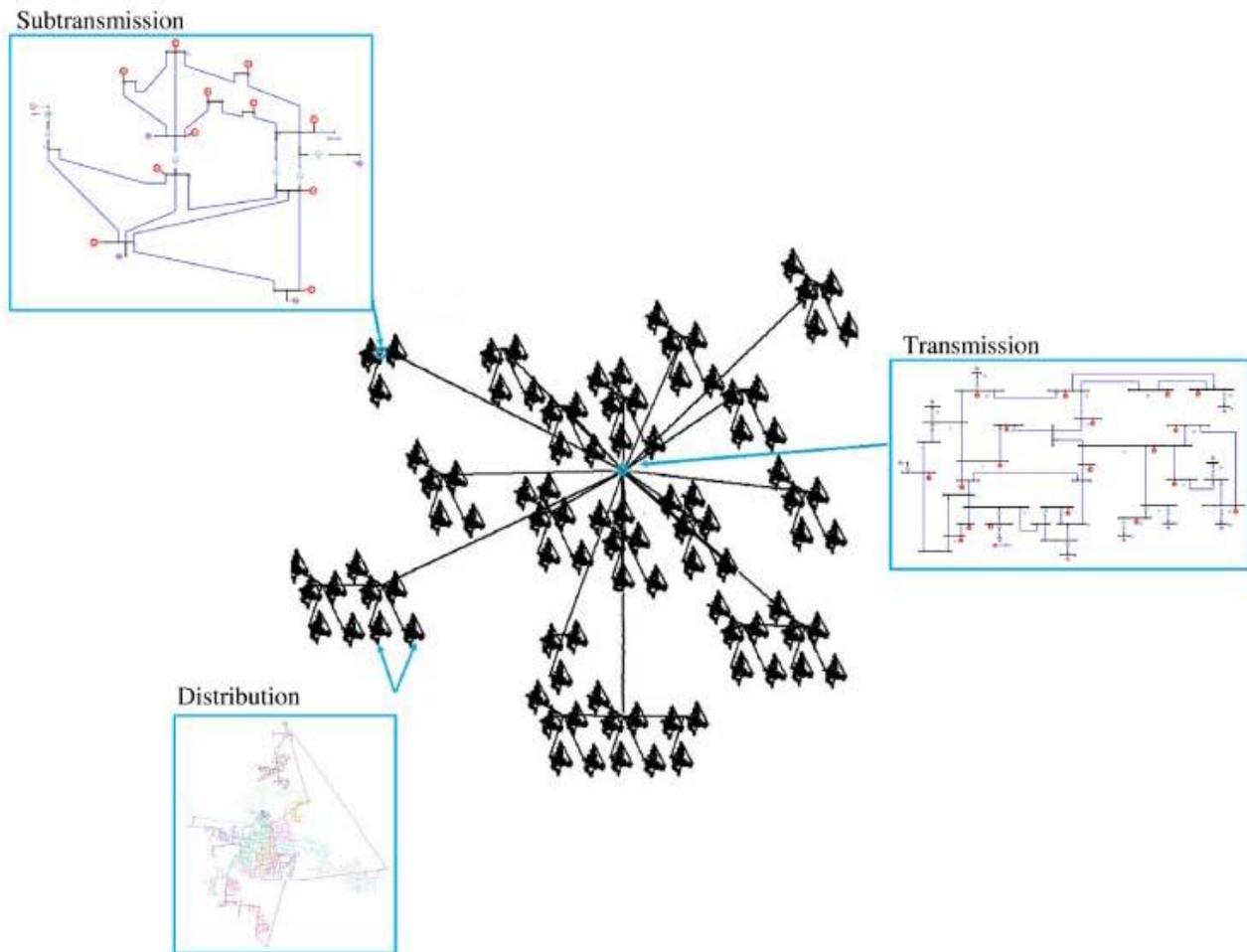


Figure 13. Load and DER representation in power flow and dynamic analyses⁷.

Each approach has pros and cons, the simplified co-modeling method is certainly the most straightforward and common technique but is not able to identify DER impacts with enough spatial granularity and accuracy. It represents a short-term solution, for instance, for power delivery systems with low to moderate penetration levels of DER, where complex interactions between transmission and distribution systems are not expected. The specialized literature indicates that integrated transmission and distribution models are robust, detailed and accurate, however, they require converting and consolidating models from legacy software solutions to specialized software tools with capabilities for joint modeling of transmission and distribution systems. This can be a time-consuming and complex task, particularly in large electric utility systems. Nevertheless, this represents a suitable long-term approach to understand complex interactions between transmission and distribution, such as those that may occur in power delivery systems with high penetration of DER. Finally, co-simulation has the advantage of leveraging existing models and software solutions, which are coupled together

⁷B. A. Bhatti et. al, Integrated T&D Modeling vs. Co-Simulation – Comparing Two Approaches to Study Smart Grid, 2019 IEEE PES General Meeting, Atlanta, GA, <https://ieeexplore.ieee.org/document/8973761>

through a simulation framework. This technique has allowed using legacy models and software solutions, which reduces the modeling effort, and may represent a potential mid-term solution for systems with high penetration of DER, while integrated transmission and distribution models are developed. A key advantage of co-simulation is the possibility to model other systems of interest and critical infrastructure that can influence DER and power system operation, such as information, telecommunications, energy (e.g., oil and gas), and transportation systems. If such modeling is required, then co-simulation is the most suitable option. Figure 15 shows a conceptual representation of the Hierarchical Engine for Large-Scale Infrastructure Co-Simulation (HELICS)⁸, which is one of the most sophisticated co-simulation frameworks currently available. HELICS has been developed by the U.S. Department of Energy (DOE); it is an open-source co-simulation framework designed to integrate simulators designed for separate transmission, distribution and telecommunications domains to simulate regional and interconnection-scale power system behaviors. HELICS’s target is to co-simulate a 50,000-node transmission system with millions of distribution nodes, coupled with 100,000 telecommunications points.

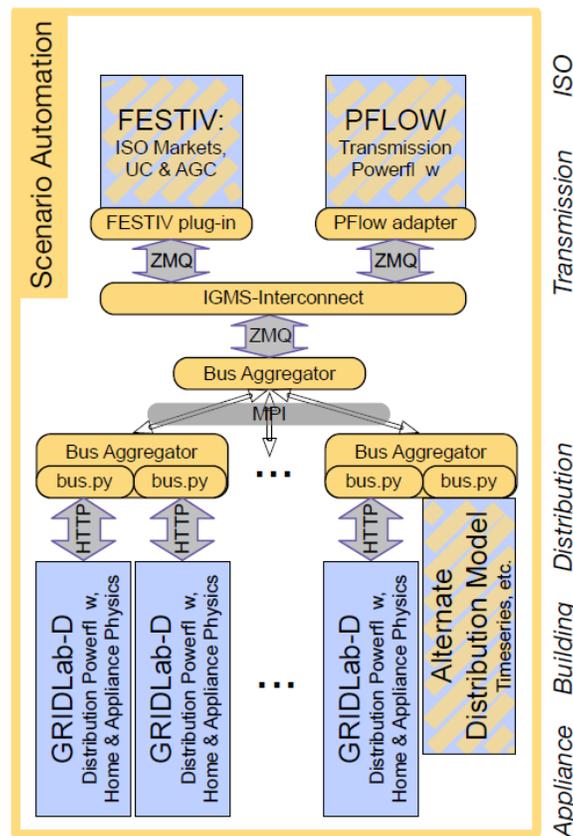


Figure 14. Example of co-simulation framework to model transmission and distribution systems⁹.

⁸<https://helics.org/>

⁹B. Palmintier, Integrated Models for Transmission and Distribution, 2016 IEEE PES General Meeting, Boston, MA, <https://www.nrel.gov/docs/fy18osti/66996.pdf>

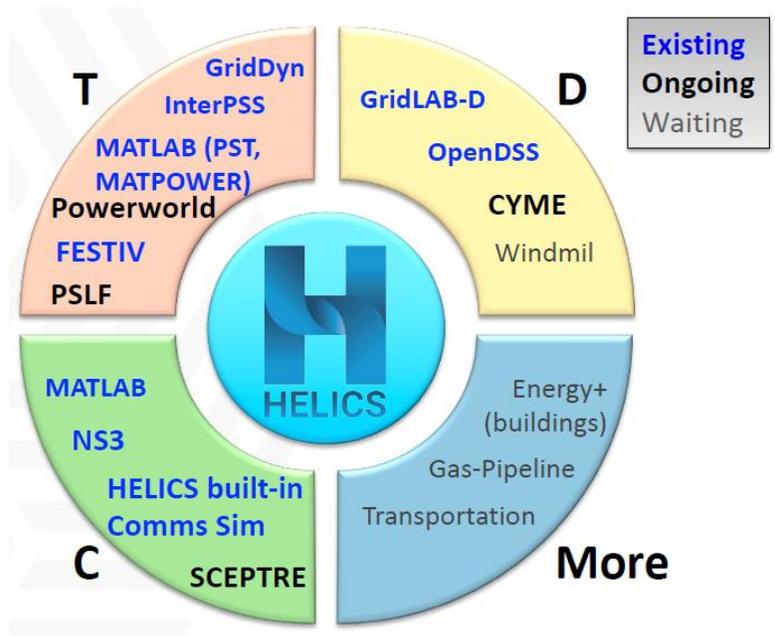


Figure 15. Conceptual description of HELICS co-simulation framework.

Appendix B — Fault Behavior and Islanding Detection

B.1 Fault and Unintentional Islanding

B.1.1 IEEE 1547-2018 Requirements for DERs During Faults

Clause 6.2 of 1547-2018 deals with DER response to area EPS faults and open-phase conditions. This clause says that when there is a fault on the section of the distribution circuit to which the DER in question is connected, that DER must “cease to energize and trip”. “Cease to energize” means that the DER must stop all real output and limit reactive exchange to only that required to energize AC-side filter elements. “Trip” is defined in 1547 as an inhibition of the immediate return to service, as opposed to “momentary cessation” in which the DER can resume output immediately upon return to normal of the system conditions. Note that “trip” in this case does not include a requirement for galvanic isolation of the DER from the distribution circuit. The standard also says that if the fault is undetectable by the utility’s own protection, such as a high-impedance fault, then there is no required response from the DER.

B.1.2 Inverter Response to Faults

To a certain extent, inverter behaviors will be case-specific because much of inverter behavior is either determined or heavily influenced by the control software. However, the following general observations can be made.

Speaking generically, the fault response of a grid-tied inverter can be subdivided into three parts as shown in the representative example¹⁰ depicted in Figure 16. The regions are:

- 1) **Initial spike:** an initial, brief spike of non-fundamental-frequency current, primarily from the discharge of the inverters’ output filter capacitors into the fault. This current may reach higher than 2 per unit (pu) on the inverter’s base rating [1], but it typically lasts only a few hundred microseconds or less. It must be noted that this transient current is not a fundamental frequency current and it should not be used as the basis for any modeling in short-circuit analysis based on phasor modeling. For example, the industry does not represent capacitor bank or cable capacitance outrush currents during faults in short-circuit analysis. These high-frequency currents are typically filtered out and not recognized by modern relays, although they may be of importance to current-limiting fuses.
- 2) **Regulation period:** during this period, the inverter controls are operating to bring the DC link voltage back into regulation, often down a steady state current limit of 1.2 pu. The length of this period is often about 50 ms but ranges from a few milliseconds to as much as 200 ms and Varies considerably inverter to inverter because it depends on the speed of the current regulation loop. Further specifications of current response in future revisions of IEEE 1547 could reduce the uncertainties in inverter response during the regulation period.
- 3) **Current-limited period:** during this period, the inverter output current reaches an approximately constant value and holds there. For remote faults that produce only small voltage drops, the inverter output current can be the

¹⁰This is purely a representative example; individual tests can and do produce different results.

current that delivers the inverter's commanded power to the circuit, if that current is lower than the maximum current.

The sequence components of a three-phase inverter's output current during the current-limited period depend greatly on that specific inverter's control design. Some three-phase inverters exhibit a very high (nearly infinite) effective negative sequence impedance due to control algorithms designed to cancel negative-sequence currents, and these inverters' fault current during the current-limited period will be almost entirely positive-sequence, with a very small negative-sequence component. Other three-phase inverters do not use such cancellation and have much smaller effective negative sequence impedances (typically, on the order of one per-unit on the inverter base), and these will produce much more substantial negative-sequence current during an asymmetrical fault. And even other (more recent) inverters are designed to provide a controlled negative-sequence current which can help coordinate with existing grid protection. *Most* inverters have a zero-sequence open-circuit and thus do not produce or allow flow of zero-sequence current, although there are exceptions.

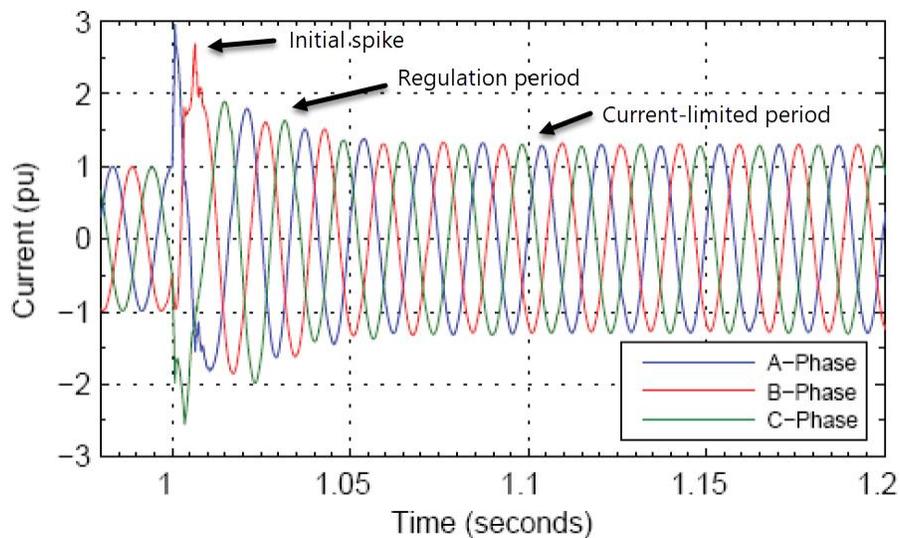


Figure 16. Typical or generic inverter fault current response.

The discussion above gives a generic and somewhat theoretical overview of inverter fault response, but bear in mind that the actual response of a given inverter to a given fault may deviate significantly from this behavior. Some examples of common deviations from the waveform in Figure 16 include:

- The magnitude and duration of the initial spike will depend on system and inverter impedances, and it may not always be present.
- The maximum magnitude reached during the regulation period, and the duration of the regulation period, are highly inverter-specific.

- The magnitude of the current during the current-limited period Varies from inverter to inverter over a wide range. A magnitude of around 1.2 pu of the inverter’s rating is common, but some inverters produce much more than that, either because they are designed for such high currents or because the inverter is de-rated (i.e., its rated current is lowered). There are also examples of legacy inverters that reduce their currents to less than 1.0 pu during the current-limited period.
- The inverter current during the current-limited period may be non-sinusoidal. For example, many inverters implement current limiting by flattening the peaks of the inverter output current. Also, during an arcing fault or other situation in which the voltage at the inverter terminals becomes very “noisy”, the inverter output may become non-sinusoidal as the inverter attempts to follow the noisy voltage.
- The inverter may cease to energize at any point during these three periods for many different reasons, which means that in some cases and for some inverters the current-controlled or power-controlled periods may not occur at all because the inverter may cease to energize due to a fast-protective mechanism prior to reaching those periods.
- The speed of inverter controls will make a significant difference in the response.

The observations above are consistent with the data shown in [10] and [11], although [11] deals only with single phase to ground faults. Also, note that once the utility’s protection opens to isolate the fault, the inverter is islanded and must cease to energize and trip prior to the first reclose attempt of the utility protection, and in no more than 2 seconds in any case.

B.1.3 Inverter Fault Current Contributions and Behavior and Interaction with System Protection

The power semiconductors in inverters can be damaged by overcurrents [12]. Mostly for that reason, as noted in the previous section, the sustained output current of grid-tied inverters is limited by several mechanisms, including fast-acting current limiting controls software that cause the inverter output current to be hard-limited to a design-specific threshold, and even faster-acting hardware-based mechanisms that will cause the inverter to cease to energize for excessively large transient spikes. Thus, during a fault transient in which the inverter does not cease to energize immediately, the maximum inverter output current into a fault is a known quantity that for grid-tied P-Q regulated inverters is typically between 1.1 and 1.4 pu on the inverter’s rated base. (For inverters designed for stand-alone, V-f regulating operation, the momentary surge current capability is often higher.)

When modeling an inverter’s current contribution to a fault for purposes of determining impacts on distribution circuit protection, one can generally get a reasonable and conservative result by assuming that until the inverter reaches a cease-to-energize time limit at a specific voltage, the inverter produces a fault current equal to its current-limited value of output current¹¹, which is commonly given on inverter data sheets as the “maximum current”. Note that nearly all bolted faults on the same distribution circuit as the inverter will pull the inverter terminal voltage below 0.71 pu, which is the voltage level at which the current required to get back to full power is equal to 1.4 pu on the inverter’s base rating. Thus, an

¹¹Note that this is NOT true for determination of inverter over-voltage contributions.

inverter operating at full power prior to the fault will reach and stabilize at its maximum (limited) current for nearly all faults at any location on the same distribution circuit [13].

B.1.4 Impact of Advanced Inverter Functionality on Fault Current

Fundamentally, advanced inverter functionality should have very little impact on inverter fault current response. The three basic regions of the fault response, and the current-limiting mechanisms described above, will remain essentially unchanged. However, the *duration* of an inverter's response to certain faults will be impacted. This is deliberate; it is actually desirable that distribution-level inverters continue to produce output during, and maintain output after, remote fault events that do not cause the terminal voltage to fall below 0.5 pu, and thus P1547 requires lengthy ride-throughs of 2 seconds down to 0.65 pu voltage for Category II, and 10 seconds down to 0.5 pu voltage for Category III, along with smooth recovery of the inverter back to normal operating conditions after the voltage has returned to normal. As described above, a reasonable approximation to the inverter's fault current can be obtained by assuming the inverter will produce at its maximum current level until a cease-to-energize time limit is reached.

B.2 Open Phase Detection

B.2.1 IEEE 1547-2018 Requirements

Open-phase detection is covered in Clause 6.3 of 1547-2018. That clause says that a DER must “cease to energize and trip” all of its output phases (i.e., all three phases of a three-phase inverter) within 2 s if there is a phase open at the Reference Point of Applicability (RPA), which depending on the system size and configuration is either the point of interconnection or the inverter terminals. The standard provides decision criteria to determine which is the RPA for a specific DER plant. There is no requirement in 1547-2018 to detect an open phase at any other location on the Area EPS.

B.2.2 Voltage Reconstruction Phenomena on an Open Phase

It is well known that elevated voltage levels can occur downstream of a circuit opening, even if no DERs are present. There are several mechanisms that can reconstruct voltage on the open phase. A brief overview of some of these mechanisms is given in [14] on the high-side bus of the transformer and in [15] located anywhere on a distribution circuit. Stated briefly, certain transformer configurations and also certain loads such as motor loads can provide coupling mechanisms between the open and still-closed phases such that voltage will appear on the open phase, again without any DERs present. This is one reason that line workers always treat conductors as energized [16], [17] unless they lock out and intentionally ground.

B.2.3 Impact of Smart Inverters with Open Phase

When a three phase DER is downstream of an open phase such as in Figure 17 several characteristics make detection difficult in cases where the DER output and the load on the open phase below the SPO are well-matched. This case is similar to that of an unintentional island in which close generation and load matching leads to a situation in which little to

no current is interrupted when an island forms. In the open phase case the DER is not actually islanded because two phases are still connected to the grid, so traditional “anti-islanding” will likely not be effective in detecting SPOs.

B.2.4 Detection Options

As noted above, 1547-2018 requires SPO detection by DERs *only* at the RPA. For those DER plants for which the Reference Point of Applicability (RPA) is at the Point of Interconnection (POI), if the DER GSU transformer is capable of supplying zero-sequence current, then zero-sequence current relaying appears to be the most reliable means of SPO detection at the POI [15]. If the GSU transformer does not have that property, then negative sequence current or voltage relaying should be effective for detecting an SPO at the POI. Reference [14] discusses means for detecting an SPO on the high side of a transformer, using only measurements taken on the low side.

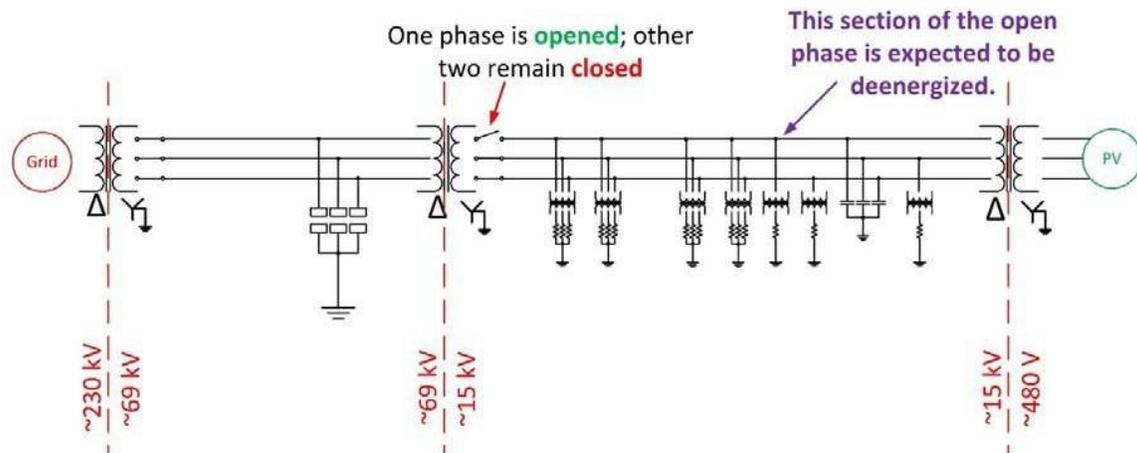


Figure 17. Diagram showing an SPO, in this case at the feeder head-end breaker.

However, an SPO can occur anywhere on a circuit [68], and detection of an SPO arbitrarily located on the circuit is considerably more difficult. There are multiple reported events of inverters in the field responding in unexpected ways to an SPO [68]. In some cases, it appears that commonly used threshold-plus-delay techniques applied to any sequence voltage or current will fail to detect arbitrarily located SPOs on distribution circuits, and the presence of three-phase rotating load or generation increases the level of difficulty [15]. This is an active area of investigation.

B.3 Inverters and Transient Over-voltage

B.3.1 IEEE 1547-2018 Requirements

Two clauses, 7.4.1 and 7.4.2, cover the allowable contributions to over-voltages by inverters. Clause 7.4.1 sets a limit of 1.38 pu¹² on line-ground or line-line over-voltages that persist over one power system cycle or more. The value of 138% is the voltage that corresponds to a coefficient of grounding (CoG) of 0.8, which defines an effectively grounded circuit. Note

¹²Per-unitized to the nominal RMS voltage at that location.

that Clause 7.4.1 does not specify the means by which the over-voltage is to be limited, and thus it does not explicitly require a grounding transformer.

Clause 7.4.2 provides new limits for DER contributions to Transient Over-voltage (TrOV) of shorter duration than those covered in 7.4.1. The TrOV limitations are expressed in terms of a TrOV magnitude-duration curve that is similar to the one used by Hawaiian Electric [18], which in turn was loosely based on previous guidance provided by manufacturer associations [19]. Violations of this magnitude-duration curve are to be calculated using the total duration of voltage above a value during any one-minute period (“cumulative duration”). Notable features of the curve are that any over-voltage above 2.0 pu^{13} for any duration is considered a violation, and the curve sets no limits for voltages below 1.3 pu .

B.3.2 Ground Fault Over-voltage with Inverters

It is well known that synchronous machines can produce a Ground Fault Over-voltage (GFOV) on four-wire circuits during a single phase to ground (1LG) fault. The physical mechanism behind this is that the synchronous machine maintains phase-to-phase voltage relationships after the circuit’s protection disconnects the circuit from the utility source [20], [21]. Because the phase-to-phase voltages are roughly fixed, but one phase is shorted to ground (i.e., its line-ground voltage is zero), the line-ground voltages of the unfaulted phases must rise, resulting in a large zero-sequence voltage. The means for mitigating this situation is the use of a properly sized grounding transformer [22] or equivalent means of providing a low-impedance zero-sequence path to ground at the DER.

However, inverters operate as power-regulated current sources, and do not maintain phase-to-phase voltage relationships. For an inverter that appears to the four-wire distribution circuit as a set of three-phase current sources, the zero-sequence component of the voltage seen at the DER terminals is determined by the impedance between the current sources and the fault, and the total load impedance connected phase-to-ground. The inverter does not exhibit the traditional GFOV mechanism seen in synchronous generators, and a grounding transformer is not the appropriate mitigation strategy to prevent GFOV on the distribution circuit. Also, when modeling GFOV driven by inverters, accurate results can only be obtained if the load impedance is included [21], [23], because it is the load impedance that completes the zero-sequence circuit.

Based on the discussion above, if the inverter’s GSU transformer is YG:yg and at least a significant fraction of the load is connected phase-ground, then no GFOV is expected on the distribution circuit. In this situation, fast relaying in the inverters is the best way to prevent any over-voltages. If a delta to grounded-y (D:yg) transformer is used, the situation is a bit more complicated. First: the effectiveness of any relaying downstream from the delta winding will be diminished because relays in that position cannot “see” the zero-sequence components on the other side of the transformer. Second: if there is significant load present with the DER on the grounded-y side of the transformer, then the current source of the DER and the shunt load combine to form a Norton equivalent source that *will* produce and reinforce a specific terminal voltage, which can be readily seen by transforming the Norton source to its Thevenin equivalent. The Thevenin equivalent

¹³The TrOV voltage-duration curve is per-unitized to the nominal *peak* voltage at that location, *not* the RMS. The peak and RMS per unit bases differ by a factor of $\sqrt{2}$.

source and the delta transformer winding combine to present an ungrounded voltage source to the circuit upstream from the delta winding, meaning that the “traditional” GFOV mechanism *does* exist on the delta side of the transformer in this case and GFOV approaching the 1.73 pu value can occur there. An example of this situation is a D:yg substation transformer serving distribution circuits with significant DER deployment levels, like the example shown in Figure 18, or for a DER collocated with a facility served by a transformer with a delta high-side winding. At present, the best option for detection of GFOV upstream from a delta transformer winding is often 3V0 relaying on the delta side.

B.3.3 Impact of Advanced Inverter Functionality on GFOV

GFOV detection by inverters interfaced by YG:yg GSU transformers likely will not be significantly impacted by the addition of advanced inverter functions and ride-throughs, because the faulted phase voltage will likely drop into the momentary-cessation region where DERs are allowed to cease output quickly. As noted earlier, the primary detection method for GFOV upstream from the delta winding of a D:yg transformer is generally 3V0 on the delta side, which is unaffected by inverter ride-throughs. If 3V0 is not used in this case, detection of the 1LG fault may be reliant on inverter unintentional islanding detection (discussed further below) after the utility protection opens to clear the 1LG fault. The problem with this situation is the speed of detection; in many cases, particularly when ride-throughs are enabled, unintentional islanding detection would allow the GFOV to persist for long enough that the P1547 cumulative-duration TrOV curve would be breached.

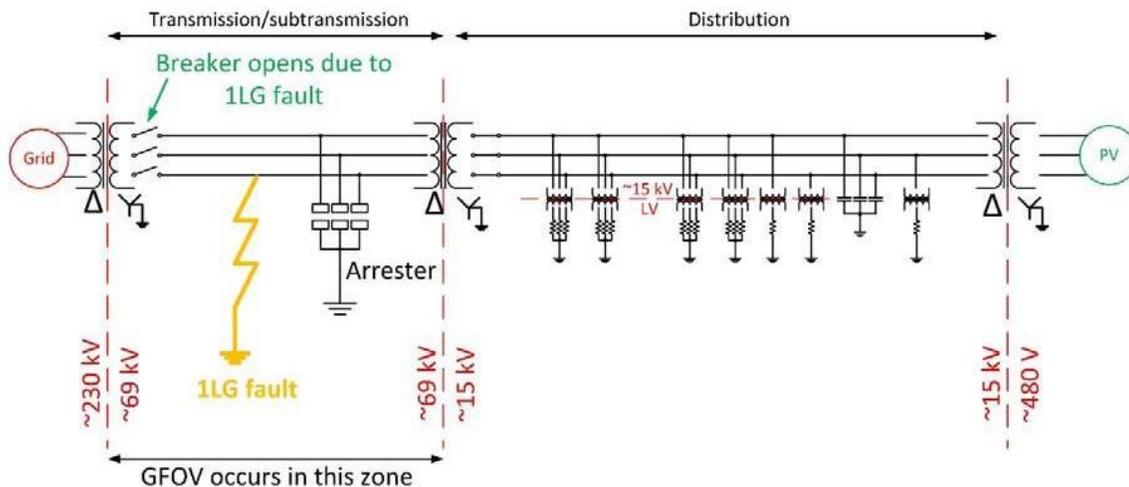


Figure 18. Diagram of a GFOV event upstream from a substation with a D:Y_G transformer.

B.4 Load Rejection Over-voltage (LROV)

Load Rejection Over-voltage (LROV) can occur if a section of a power system that is exporting power is suddenly islanded. The DERs within the island, which are assumed to be in PQ-regulated current-controlled mode, will not change their output current immediately, so the excess current that was being exported while grid-tied must flow into the loads during the first moments of the island, resulting in a voltage spike or surge.



B.4.1 Inverters and LROV

Fortunately, there are some inherent mechanisms in inverters that tend to limit LROV. The first mechanism is a property of the way inverters control their output current: as the AC voltage rises relative to the inverter’s DC voltage the inverter’s ability to source current is diminished, so the onset of LROV actually helps to curtail the excess current output that led to the LROV in the first place. Once the AC voltage reaches the inverter’s “clamping voltage”, which is the DC link voltage multiplied by any appropriate transformation ratios, the inverter’s inherent antiparallel rectifier will begin to conduct and will act to clamp the AC voltage to the DC link voltage. Thus, in theory, any longer term LROV driven by inverters (excluding initial transients and resonances) can rise no higher than the inverter DC link voltage.

The second mechanism is that most (but not all) inverters have a Self-Protection Over-voltage (SPOV) mechanism that operates on peak (not RMS) voltages and causes the inverter to cease output very quickly, typically in 1 ms or less, if the instantaneous voltage increases beyond a pre-determined limit. The SPOV mechanism, as the name implies, is intended to protect the inverter against damaging AC side voltage transients, but it has the added benefit of preventing many types of transient over-voltage, including LROV.

B.4.2 Impact of Advanced Inverter Functionality on LROV

The property that output current capability is impacted by rising AC voltage, and the antiparallel-rectifier clamping mechanism, should not be significantly impacted by the addition of advanced inverter functions. The clamping mechanism is impacted by the DC link voltage, and the present trend toward higher DC link voltages may mean that LROV could become more of a problem in the future. There could potentially be some impact of new inverter requirements on LROV because Clause 6.4.2.4 of P1547-2018 does require high-voltage ride-through capability, but the requirement to trip at 1.2 pu is essentially unchanged from 1547-2003, so this impact should be small.

B.5 Unintentional Islanding Detection

An “island” in a power system is any section of the power system that has its own generation and loads, and thus can operate autonomously for at least some period of time. Intentional islands can be beneficial to system reliability and resiliency, and P1547 Clause 8.2 outlines requirements for certain types of intentional islands. However, an island may be formed unintentionally if a section of the power system containing grid-following (PQ-regulated) DERs and loads is isolated by a breaker or other interrupter. Such unintentional islands do not have planned and coordinated protection or voltage and frequency controls, may drift out of phase with the grid and thus create a risk of asynchronous reclosure, and may be operating without the awareness of utility or other personnel, so extended operation of an unintentional island could pose risks to equipment and possibly to human safety. IEEE 1547 makes it the responsibility of the DER to detect and cease to energize an unintentional island according to the requirements described above.

B.5.1 IEEE 1547-2018 Requirements

Clause 8.1.1 states that a DER is responsible for detecting formation of an unintentional island within 2 s of island formation, which is the same requirement as was in 1547-2003. Clause 8.1.2 of P1547 provides a new allowance for

extending the clearing time to as much as 5 s upon mutual agreement between the DER operator and the Area EPS operator. Finally, in Clause 8.1.3, 1547-2018 emphasizes that islanding clearing times must be coordinated with the Area EPS's first reclosing interval. This requirement was also in 1547-2003, but language has been added to ensure that readers are aware that there is a requirement in addition to the 2-s detection, and that may be shorter than 2 seconds.

B.5.2 Methods for Unintentional Islanding Detection

Islanding detection methods can be broadly grouped into three categories: passive inverter-resident, active inverter-resident, and non-inverter-resident.

Passive inverter-resident methods generally involve processing of the inverter's terminal voltage to look for signatures that may indicate that an unintentional island has formed, and there are no changes made to the inverter's output current *specifically* for the purpose of detecting an island. Examples of inverter-resident passive methods include over/undervoltage, over/underfrequency, and RoCoF, all of which rely for island detection on some imbalance between the sources and sinks of active and reactive power within the island. Further discussion is provided in [27]–[30]. Passive methods do not require that inverters destabilize the power system, and thus should have little to no effect on power system transient stability, and they also do not adversely impact power quality. However, most passive methods depend for their effectiveness on the existence of an imbalance between generation and loads within the island, or on a change in the power system's properties when the island forms. If such imbalance does not exist or if that change in system properties is too small, then the change in inverter terminal voltage that triggers the passive method will not occur and a nondetection zone (NDZ) will exist. All inverter-resident passive methods have an NDZ.

Active inverter-resident methods involve feedback of some aspect of the inverter's terminal voltage, such as its frequency or its phase angle relative to the inverter output current, to cause a change in the inverter's output current that causes the island to be detected. There are several physical mechanisms that can be used as the basis of an active inverter-resident method, which are described in [27]–[30] and [67], and many proprietary Variations of these methods exist in industry. The active inverter-resident methods can also be described by the Group numbers that are defined in [58], [59]. The most common active inverter-resident method involves positive feedback on frequency: if the inverter detects that the frequency of its terminal voltage has changed, the inverter then changes the frequency of its output current in such a way as to make the change in voltage frequency larger. There are many Variants of this method. Positive feedback on frequency can lead to an islanding detection method with an extremely small NDZ, and positive feedback on frequency has the added advantage of tending to automatically synchronize the anti-islanding efforts of multiple inverters because the voltage frequency is at least roughly the same at all inverters within an island. However, positive feedback on frequency by its very nature destabilizes the power system, and there is already some evidence that at high penetration levels anti-islanding based on positive feedback on frequency can adversely affect bulk power system dynamics [64]. Positive feedback on other quantities can also be used: for example, for three-phase inverters it has been proposed to use positive feedback on the negative sequence voltage.

Non-inverter-resident methods include any method that relies for islanding detection on a device outside the inverter, or a communications signal sent from another point on the system. Communications-based methods such as DTT fall into this category, and communications-based methods using synchrophasors have also been explored [65], [66]. The use of grounding switches or the toggling of system capacitors on opening of a breaker are also in this category. Non-inverter-resident methods generally have extremely high islanding-detection effectiveness and generally work for all combinations of DER. Their primary disadvantage tends to be cost, especially for the communications-based methods.

Nearly all inverters available today for connection to power grids use both passive and active inverter-resident methods. Of the non-inverter-resident methods, the most common example is direct transfer trip (DTT), but there are many other such methods available, and many investigators today are looking into non-inverter-resident methods using communications between the system and the DERs. There are several good reviews of the available islanding detection methods available in the literature, and for brevity these will not be repeated here. The reader is directed to references [27]–[30] and [67].

B.5.3 Impact of Advanced Inverter Functionality on Unintentional Islanding Detection

B.5.3.1 Ride-Throughs

DERs are required by 1547-2018 to ride through certain abnormal voltage and frequency conditions, and these requirements are new to the 2018 version. The ride-through requirements do not apply during an unintentional island, but DERs do not have a way to “know” whether an abnormal voltage or frequency is caused by an unintentional island or by a condition in which ride-through is required, and thus it is generally not possible to disable ride-throughs during an unintentional island event. It is generally accepted at this time that the addition of ride-throughs will make it more challenging for DERs to detect and cease to energize an unintentional island. The voltage and frequency ride-throughs will cause the passive inverter-resident methods to have much larger Non-Detection Zones (NDZs) than they did under 1547-2003. The over/under-voltage and over/under-frequency relays will obviously have much larger NDZs when ride-throughs are required, and certain passive inverter-resident relaying functions that are commonly used as part of islanding detection, such as vector shift and Rate-of-Change-of-Frequency (RoCoF), will be rendered far less effective by the RoCoF¹⁴ and phase-jump¹⁵ ride-through requirements in 1547-2018.

It is intuitive that ride-throughs will extend the run-on times of active inverter-resident islanding detection methods because the trip limits they use have been moved “farther away” from nominal meaning that it will take slightly more time to reach them. However, simulation-based and experimental evidence [18], [29], [58], [59] has found that while this is true, the impact appears small and in many cases will not lead to non-compliance with the 2 s detection requirements in 1547-2018. The ride-throughs may have the side effect of compelling manufacturers to make their islanding detection more aggressive to ensure adequate protection and standards compliance, and this could have impacts on system

¹⁴The RoCoF ride-through requirements are in Clause 6.5.2.5.

¹⁵The vector shift ride-through requirements are described in Clause 6.5.2.6.

transient response at high penetration levels. However, this is not a foregone conclusion; there are methods that may allow retention of active anti-islanding effectiveness without requiring excessive increases in destabilizing gains [59].

Most of the non-inverter-resident methods, such as communications-based methods, are minimally affected by the presence of ride-throughs.

B.5.3.2 Grid Support Functions

Grid support functions are also expected to adversely impact the islanding detection effectiveness of passive inverter-resident methods, particularly when used in conjunction with ride-throughs. It is less clear how grid support functions, such as frequency-watt and volt-VAr droops, will impact inverter-resident active methods, but there are preliminary indications that this impact may be negligible [28]–[30] in part because the droop functions operate much more slowly than the anti-islanding and in part because some of these functions cause cross-coupling between parameters that can actually help make islands *easier* to detect. This is still an active area of investigation.

Most of the non-inverter-resident methods are minimally affected by the addition of grid support functions.

Appendix C — Ride-Through Capability

C.1 Introduction

Recent events on the bulk power system (BPS) have illustrated the importance of ride-through capability for inverter-coupled resources connected to the transmission system as well as the distribution system. In August 2016, a normally cleared 500 kV fault caused by the Blue Cut Fire in the Southern California area resulted in approximately 1200 MW of BPS-connected solar PV resources tripping offline due to frequency and voltage related protective functions [34]. On October 9, 2017, normally cleared faults on the 220 kV and 500 kV systems resulted in approximately 900 MW of BPS-connected solar PV resources tripping by voltage protective relay actions. For both disturbances, no generating resources were disconnected as a direct consequence of the fault. Rather, the inverters tripped offline due to their response to the detected terminal voltage and frequency conditions. Early events in 2003 and 2006 in the European grid initially identified the need for wider frequency ride-through requirements that align with BPS dynamic performance during system separation or other large frequency deviation events [30]. In particular, the potential widespread disconnection of resources at 50.2 Hz (200 mHz frequency deviation from nominal) was determined by study to have a detrimental impact on grid reliability, and this instigated a retrofitting of hundreds of thousands of solar PV systems larger than 10 kW between 2012 and 2014 [40]–[43]. All events have supported the broad conclusion that any element connected to the electric grid should protect itself from damage, but should also be designed and built to withstand specified abnormal voltage and frequency conditions to support stability and reliability of the interconnected BPS [38].

The operating mindset until recently has been that distributed energy resources (DER) should disconnect or cease energization whenever voltage or frequency conditions fall outside normal operating ranges. Outside these ranges, the DER “must trip” to not exacerbate the problem. This was historically based on distribution system safety concerns around detection of islanded DER operation, safe maintenance, and local protection system coordination. However, this mindset has changed with the recent revision of IEEE Standard 1547, the de-facto interconnection standard for DER in North America, providing greater focus on the overall impacts and necessity of ride-through capability of all generating resources connected to the electric grid while still ensuring safety and equipment reliability. Ride-through is intended, first and foremost, to ensure continuity of generation to serve the end-use loads following abnormal operating conditions. Resources are expected to ride through grid frequency and voltage excursions so as not to contribute to adverse system operating conditions, coordinate with wide-area safety nets such as under-voltage load shedding (UVLS) and under-frequency load shedding (UFLS), and to avoid a greater loss of load and potential cascading outages. All resources connected to the grid can impact system frequency and local bus voltages. The ability to ride through disturbances enables grid supportive inverter features like frequency response and voltage control, which support local and wide-area system stability. At the same time, the requirements are developed with a concerted focus on grid needs, equipment limitations, and reasonable cost implications to find an effective balance between competing perspectives. As the penetration of DER and inverters continues to grow, the system becomes dependent on the essential reliability services (ERS) provided from these distributed resources, and ride-through capability becomes increasingly important [36], [37]. From a BPS reliability perspective, the desired performance is for resources to ride through to the greatest extent possible (set their voltage and



protective relay settings as wide as possible) while still protecting their respective equipment from damage and ensuring personnel safety.

Ride-through requirements for DER connected to the distribution system are specified in IEEE 1547-2018, focusing particularly on voltage and frequency ride-through as well as voltage phase angle changes and rate-of-change-of-frequency. Requirements are separated into abnormal performance Categories I, II, and III for disturbance ride-through. Category I is intended to accommodate existing technology such as rotating machines, prime mover constraints, or legacy inverter-coupled resources. Category II focuses on alignment with the BPS ride-through requirements for the entire inverter-coupled system, and other reliability needs (adding some margin to the ride-through curves) to accommodate delayed recovery of post-fault voltage at the distribution level. Category III focuses on additional requirements, mostly distribution-related, for high DER penetration systems such as California and Hawaii where both distribution system and BPS reliability significantly depend on the DER performance. Ride-through requirements for Bulk Electric System (BES) generating resources are specified in NERC Reliability Standard PRC-024-2 [35]. The requirements of abnormal performance Category II in the new IEEE 1547 standard are coordinated with PRC-024-2 and IEEE 1547-2018 requires that generator frequency and voltage protective relaying used to trip applicable generating unit(s) not be set to trip within the “no trip” zone of Attachments 1 and 2 of PRC-024-2. Footnote 1 of the standard clearly describes that these protective functions may be part of “multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs”. For BES-connected inverter-coupled resources, it is important to understand that the control actions that perform protective functions are included in the requirements specified in PRC-024-2.

The following subsections describe fundamental aspects of each type of ride-through and considerations that must be made for DER and inverter-coupled resources connected to the BPS.

C.2 Technical Discussion

C.2.1 Ride-Through Operating Modes and Curve Implementation Philosophies

While the intent of ride-through in IEEE P1547 and setting appropriate voltage and frequency protective relay settings in NERC PRC-024-2 are similar in nature, there are some key distinctions, including:

- IEEE P1547 provides both a “may trip” zone beyond the specified ride-through regions and “must trip” requirements that are separated by time and magnitude. These specifications are intended to be consistent with BPS security needs while balancing local distribution system requirements as well. Tripping for abnormal voltage (and frequency) is essential for radial distribution protection system operation, public and utility personnel safety, and customer equipment damage. This ensures that the distribution feeders do not remain energized when the utility circuit breaker or recloser is opened. It is also important that DER current contribution to severe, close-in distribution faults be discontinued as quickly as possible to minimize equipment damage, personnel risk and miscoordination of feeder protection. On the other hand, at the BPS, equipment protection should be set as wide as possible to ensure resources remain connected to the BPS and provide essential reliability services while still

protecting the equipment from damage. This inherently means that the area outside the “no trip” zone of the PRC-024-2 ride-through curves should be interpreted as a “may trip” zone and not a “must trip” zone.

- IEEE P1547 permits the use of a ride-through mode called “momentary cessation” as a form of ride-through under certain terminal voltage conditions and requires mandatory operation for other conditions. Inverters momentarily cease energization with the Area EPS until terminal conditions return to the mandatory or continuous operating range. On the other hand, resources connected to the BPS should continue injecting active or reactive current during disturbance ride-through (e.g., mandatory operation) to support the local and wide-area BPS during these conditions. Grid supportive inverters have the capability to ride through disturbances and inject specified amounts of active and reactive current to support frequency and voltage stability during and following fault conditions. From a BPS-connected resource perspective, supply of fault current from generating resources is necessary to allow protective relays to detect fault conditions and trip faulted elements. The contribution of fault current from inverter-coupled resources will have an impact on conventional protective relaying and should be considered moving forward [48], [49]. Conversely, at the distribution system, P1547 requires momentary cessation at low voltage during fault conditions so that DER do not interfere or interact with distribution protection systems. Yet, P1547 does require DER to quickly restore active current output following momentary cessation in less than 400 milliseconds.
- The ride-through philosophies of NERC PRC-024-2 and IEEE P1547 appear to conflict with one another; however, they do not since IEEE 1547 should be applicable only to distribution-connected resources while PRC-024-2 drives performance for BPS-connected resources. Care should be given to not apply IEEE P1547 requirements to BPS-connected resources and that has been explicitly noted in the new P1547. Rather, care should be given to specify equipment ride-through capability and voltage or frequency trip settings based on the jurisdiction for which the resource is being connected. Inverter manufacturers acquiring UL 1741 certification are not precluded from testing and certifying the inverter to configurable settings that meet BES connection requirements. As long as the inverter is configured appropriately for the application in which it is installed, the UL 1741 certification requirements do not conflict with NERC Reliability Standards. PRC-024-2 can be used as a source requirement document for UL testing to obtain a third-party UL certification that the inverter meets BES requirements as well as other necessary requirements. There are reliability needs and benefits behind the requirements of each standard, which necessitate some differences between BPS and distribution system interconnection requirements.

C.2.2 Frequency Ride-Through Requirements

Frequency ride-through is critical to ensure balance of generation and load across the interconnected bulk power system. This balance crosses the transmission-distribution (T-D) interface, and all resources need to ride through expected abnormal frequency conditions cohesively, with sufficient ride-through capability, to avoid any over- and under-frequency load shedding conditions. Frequency ride-through ensures that resources can continue providing ERS, including primary frequency response, during large frequency deviations [36]. IEEE P1547 specifies frequency ride-through requirements uniformly for Category I, II, and III resources for this fundamental reason (Figure 19). These are coordinated with NERC

PRC-024-2, which specifies admissible frequency protection settings for BES resources (Figure 20). As a matter of fact, the frequency ride-through capability requirements in P1547 meet and exceed the PRC-024-2 specifications. While IEEE 1547 provides some specificity around how rate-of-change-of-frequency is calculated, neither standard directly specifies the performance of frequency calculations during transient events (e.g., phase jumps, harmonic distortion, switching events, etc.). Test procedures in IEEE 1547.1 may help ensure inverters are able to withstand sub-cycle distortion and large phase jumps such that the frequency protective functions do not act on these types of conditions. However, more work may be needed to expand the degree of testing in IEEE 1547.1. Historically this has not been an issue since frequency was derived from shaft speed or calculated from a well-filtered fundamental frequency voltage waveform or through the use of discrete Fourier transform (DFT) algorithms. Inverters of different designs have employed a variety of means to determine frequency, ranging from fairly simplistic single-phase zero crossing algorithms to more advanced algorithms using intelligent filtering on the frequency reported by the PLL. In any case, the measured frequency should be filtered before any protective action is taken. Operating on raw calculated frequency will cause erroneous frequency tripping issues, as observed during the Blue Cut Fire disturbance, particularly if frequency is based on an individual phase measurement [34].

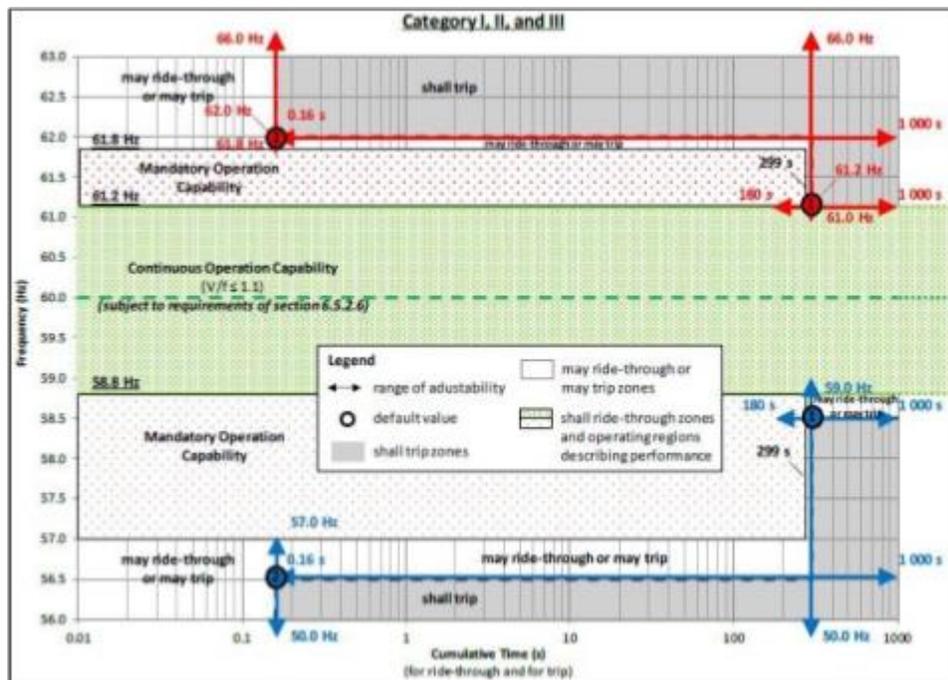


Figure 19. IEEE 1547 frequency ride-through requirements for Category I, II, and III. [Source: IEEE]

C.2.3 Rate of Change of Frequency Ride-Through Requirements

As synchronous generating resources with system inertial response are replaced with inverter-coupled resources, the rate of change of frequency (ROCOF) will increase for imbalances in generation and load. In practice, high ROCOF is not a material issue for either properly designed inverter-coupled resources or for synchronous machines. ROCOF ride-through requirements are fundamentally used to ensure the generation system-wide remains synchronized under high ROCOF

conditions such that the frequency imbalance is not further exacerbated by additional resources tripping. However, ROCOF measurements have historically been used in inverters designed for distribution applications as a means of detecting inadvertent distribution feeder islanding. Applying this distribution protection philosophy increases the potential for wide-area resource loss during high ROCOF conditions such as faults, etc., where inverters are expected to ride through.

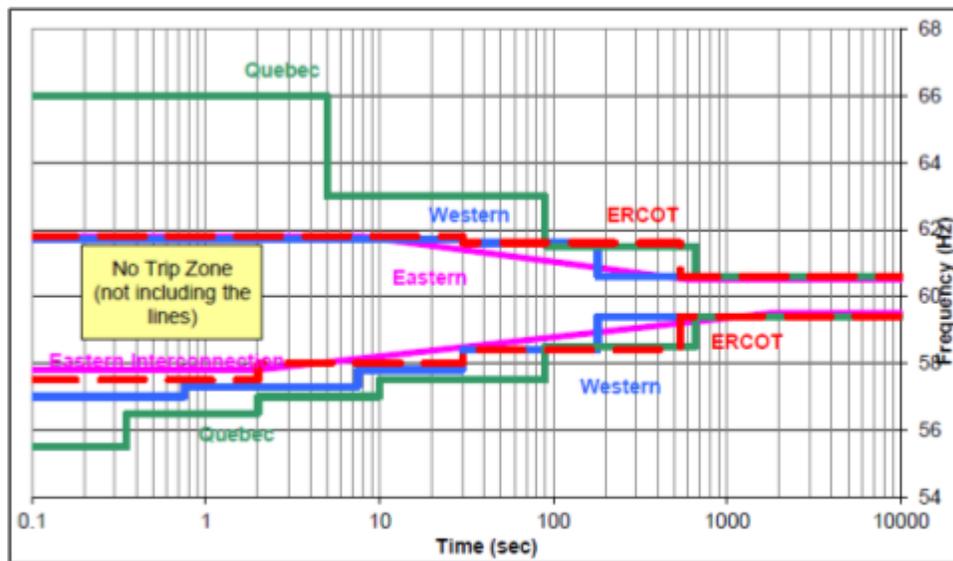


Figure 20. NERC PRC-024-2 frequency ride-through curve. [Source: NERC]

The revised IEEE 1547 now includes a ROCOF ride-through requirement (see Table 4). ROCOF is specified as the average rate of change of frequency over an averaging window of at least 0.1 seconds. No safety or equipment limitations were identified that would prohibit rigorous ROCOF ride-through requirements for DER since passive islanding detection is not widely used in North America (different from other regions such as Ireland [46]). Further, the ROCOF requirements are greater than the wide-area frequency excursion events currently experienced on the BPS (particularly Category III), with the intent of ensuring ride-through for increasing penetration levels of DER in the future.

Table 4 Rate of Change of Frequency Ride-Through Requirements in IEEE P1547

Category I	Category II	Category III
0.5 Hz/s	2.0 Hz/s	3.0 Hz/s

ROCOF ride-through is not specified by PRC-024-2 or in other standards applicable to resources connected to the BPS. While no resource, synchronous or inverter-coupled, can ride through infinite ROCOF, BPS-connected resources can be reasonably expected to ride through the current and future ROCOF values experienced across all interconnections in North America. In fact, it is recommended that any ROCOF tripping settings, possibly unintentionally used for anti-islanding protection, be disabled for BPS-connected resources so they do not inadvertently trip during transient grid conditions such

as faults. This recommendation is based on anecdotal evidence that BPS-connected inverter-coupled resources have reported tripping on ROCOF protection during phase jumps caused by fault events. The near-instantaneous ROCOF caused by fault events should be dealt with separately (discussed in more detail in the next section) and are not related to low inertia, high ROCOF systems.

C.2.4 Instantaneous Phase Angle Change Requirements

During fault conditions, the normally sinusoidal voltage and current waveforms may undergo instantaneous phase changes (known as “phase jumps”) and harmonic distortion in the electrical quantities. Large instantaneous changes in phase may create synchronism issues for the inverter phase lock loop (PLL) controls. Unlike the ROCOF requirements specified over 100 ms, phase jumps are instantaneous and inverters should ride through these short-lived phase jumps caused by faults or other switching events.

Individual phases may experience large phase jumps, particularly during unbalanced faults. Figure 21 shows the individual phase shifts of the three-phase voltages from the Blue Cut Fire disturbance [34]. The phase jumps in the two affected phases are equal and opposite, implying a relatively small change in positive sequence phase angle. It is important to recognize that these instantaneous phase angle changes are dealt with significantly differently from one inverter to the next based on their method of calculating frequency.

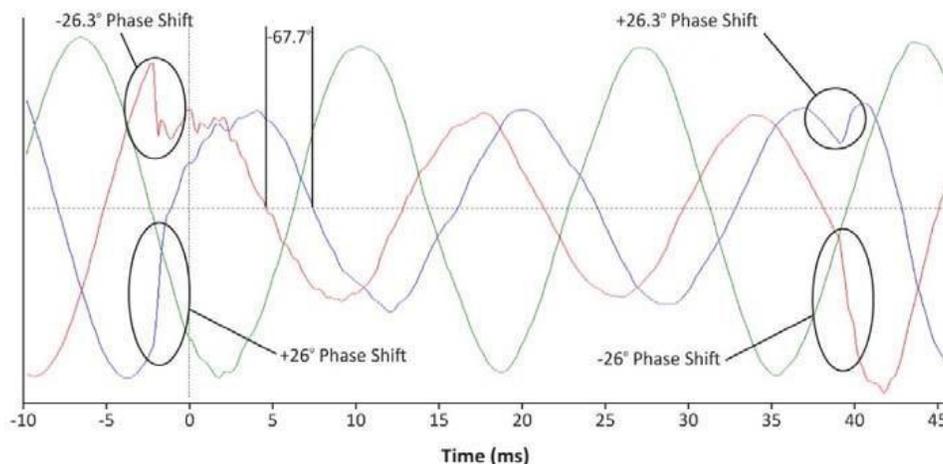


Figure 21. Phase jump from Blue Cut Fire Disturbance 500 kV fault. [Source: IEEE]

IEEE P1547 requires that multi-phase DER ride through the following in the sub-cycle-to-cycle time frame: (1) positive-sequence phase angle changes of less than or equal to 20 degrees, and (2) individual phase angle changes less than 60 degrees. Single phase DER are expected to ride through the latter since they are connected on only one phase. IEEE P1547 allows for either positively damped oscillations or the use of momentary cessation for no more than 0.5 seconds post-disturbance. At the BPS, there are currently no performance requirements for phase angle change ride-through. BES resources are expected to set their frequency protective functions (or relaying) to not trip within the “no trip” zone of the



PRC-024-2 ride-through curves, regardless of the phase jumps experienced. Frequency protective trip functions should not use instantaneously calculated frequency measurements, and should be applied towards filtered frequency calculations. Therefore, phase jumps causing spikes in calculated frequency should be filtered out by the frequency measurement for the trip functions and resources should be capable of riding through these events. While synchronous machines, in particular, are susceptible to damage for very large positive sequence phase angle changes, these situations are very rare and system design and protection can avoid the need for tripping for expected fault conditions on the BPS.

C.2.5 Voltage Ride-Through Requirements

Over- and under-voltage ride-through is specified separately for Category I, II, and III resources in P1547 since voltage ride-through is dependent on the penetration of DER, with Varying reliability needs. Figure 22 shows the voltage ride-through requirements for Category II resources in IEEE P1547. DER is expected to maintain synchronism to the distribution system and continue injecting current to the grid during continuous operation and mandatory operation ranges. Below or above specified voltage ranges, the DER may cease injecting current to the Area EPS and enter into momentary cessation during these low voltage conditions (permissive operation capability). In the distribution context, very low fault voltages most often occur on the same radial circuit to which the DER is connected. Momentary cessation accelerates detection of feeder islanding conditions, reduces worker exposure to fault current effects such as arc flash, minimizes interference with protection coordination, and minimizes equipment damage. Outside the ride-through ranges, DER shall trip to ensure that the distribution feeders do not remain energized when the utility circuit breaker or recloser is opened and to ensure that the DER is not causing any excessive over-voltage condition. Lastly, the curves include a may trip area that provides a margin between the “no trip” and “must trip” regions, and accounts for equipment performance uncertainty.

NERC PRC-024-2, shown in Figure 23, differs from IEEE P1547 in that inside the “no trip” zone of the ride-through curve, voltage and frequency protective relay settings are not expected to trip the resource, and the resource should continue injecting current to the grid. Outside the ride-through curve, BPS-connected resources should set their protective settings as widely as possible while still ensuring equipment safety. Existing BPS-connected inverter-coupled resources may have limited reactive current support during voltage ride-through modes or may solely still rely on momentary cessation as a relic of vintage equipment design. Advanced inverters can enable grid-supportive functions such as dynamic voltage support during and following severe voltage excursions. Dynamic voltage support can contribute fault current, which is essential for conventional transmission protective relaying. However, specific dynamic voltage support and fault current contribution requirements are not currently specified for North American BPS-connected resources. Current activities under NERC and IEEE aim at closing this gap for ride-through specifications for inverter-coupled resources connected at the BPS level.

C.3 Areas for Future Work Related to Ride-Through

The requirements in IEEE P1547 and testing requirements being developed in P1547.1 make strides in ensuring that distribution-connected inverter-coupled resources are able to withstand expected voltage magnitude, phase, and frequency conditions during fault or other disturbance conditions. However, recent grid events and analysis of inverters during these disturbances have proved that additional work is needed in the area of testing and equipment performance

requirements to ensure comprehensive ride-through. Examples where future research and additional performance specifications could focus include:

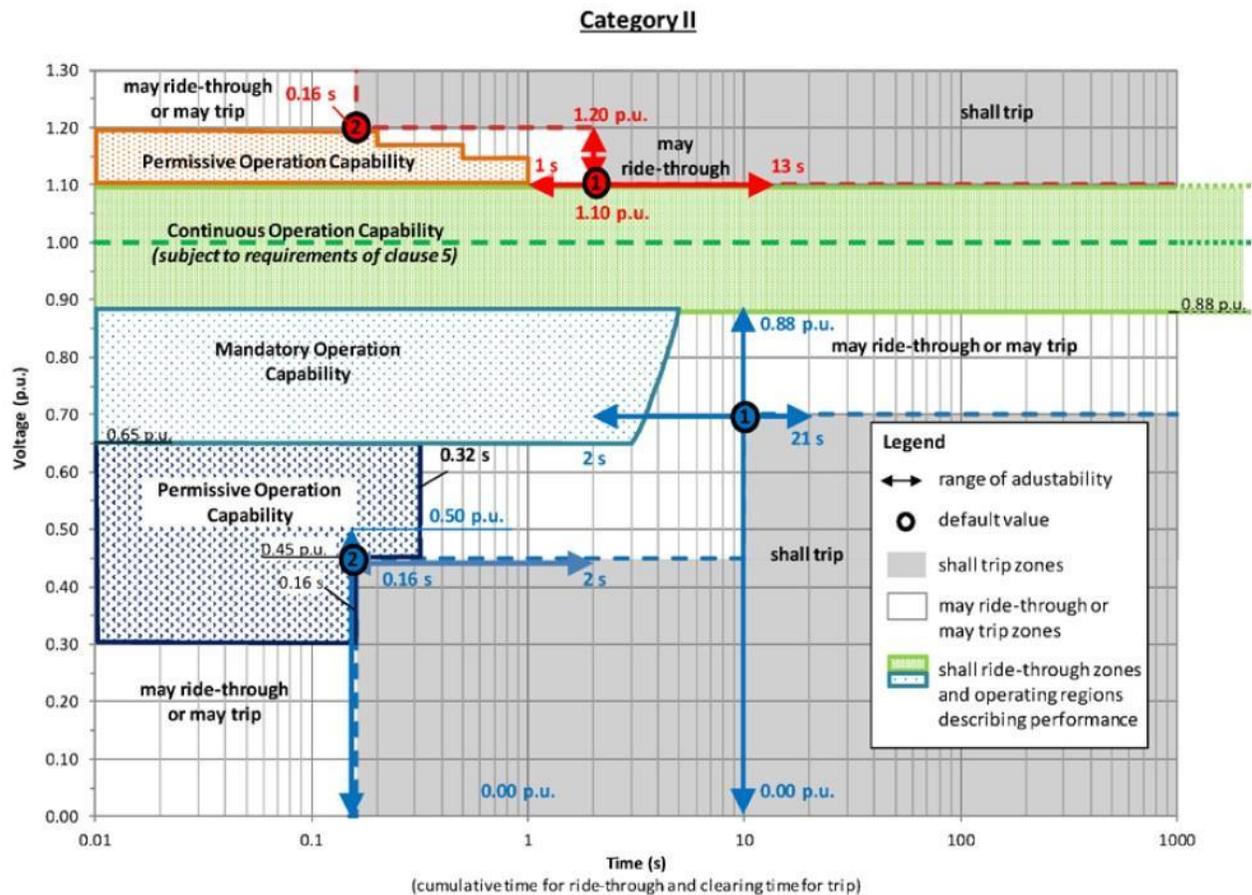


Figure 22. IEEE P1547 voltage ride-through requirements for Category II. [Source: IEEE]

- Standardizing measurement and protection techniques, including how voltage and frequency protection is applied and over what time ranges
- Standardizing testing protocols selectivity of frequency trip functions for distorted waveform tests to ensure that resources are not tripping for expected severe grid disturbances
- Standardizing testing protocols around instantaneous phase angle changes to test inverters for the most severe phase jumps they are expected to ride through
- Further refining ride-through requirements for BPS-connected resources, ensuring the requirements in PRC- 024-2 are applicable and clear to both synchronous and inverter-coupled resources
- Developing requirements and recommended practices for how voltage measurements and filtering are applied to voltage-related protective functions in inverters to avoid spurious tripping for sub-cycle voltage transients

- Developing specifications and recommended practices for protecting inverters from transient over-voltage conditions while ensuring ride-through requirements for distribution- and BPS-connected resources are met
- Standardizing the functional requirements and performance frequency protection in inverters during transient conditions
- Ensuring that the requirements (e.g., IEEE P1547, UL 1741, NERC PRC-024-2) are applied appropriately based on the jurisdiction in which the resources are installed, and that utility-scale inverter-coupled resources do not have conflicting requirements from these distinct standards.

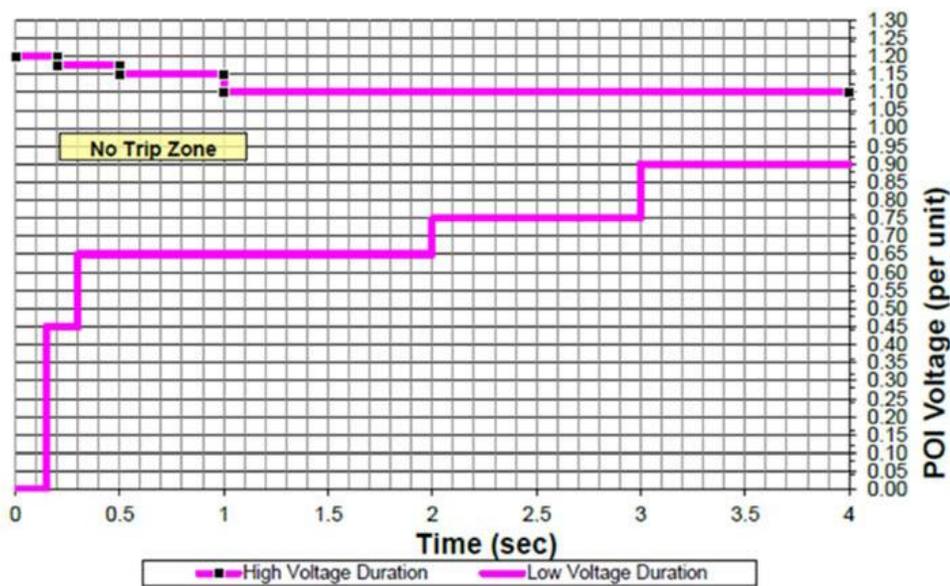


Figure 23. NERC PRC-024-2 voltage ride-through curve. [Source: NERC]

The primary goal of this proposed future work is to ensure explicit testing protocols to avoid any interpretation of the performance specifications in applicable standards and to ensure resources continue to ride through grid disturbances in a reliable manner. Results from this future work could be considered in the current or a future revision of IEEE Standard 1547.1, which complements IEEE 1547 with appropriate type tests. Findings can also be used to inform future revisions to performance-based standards for BPS-connected resources and for DER.

Lastly, guidance in the application of the new IEEE 1547 is needed. That guidance should not be limited to distribution utilities but should include the authorities governing the interconnection requirements (e.g., state regulators and interested stakeholder) as IEEE 1547 requires the assignment of normal and abnormal performance categories to specific (groups of) DER as outlined in Appendix B of the new standard and [47]. Further, these entities should understand that standards relating to DER should only be applied at the distribution system, and that applying these standards to BPS-connected resources could be a misapplication of the requirements. Inverter manufacturers acquiring UL 1741 certification for BPS-connected resources are not precluded from testing and certifying the inverter to meet BES



connection requirements as well as the requirements in IEEE 1547, and should configure the inverter appropriately for the application in which it is installed.

Within the IEEE, the following committees and working groups are working together to address these future needs:

- IEEE/PES/Transmission & Distribution (T&D) Committee, Distributed Resources Integration Working Group, <https://site.ieee.org/pes-dri/>
- IEEE/PES/Energy Development & Power Generation (EDPG) Committee, Wind and Solar Plants Interconnection Working Group, <https://site.ieee.org/pes-edpgcom-wspidsc/working-groups-and-task-forces/wind-and-solar-plant-interconnection-working-group/>
- IEEE Standards Coordinating Committee 21, <https://sagroups.ieee.org/scc21/>

Appendix D — Distribution System Planning

This section discusses: a) how planning of electric power distribution systems is evolving to address challenges and needs triggered by this new reality, and b) overall distribution planning trends and practices being followed by the industry to ensure that the distribution grid is prepared to continue providing a reliable, resilient, economic, and safe electric service to its customers.

D.1 Modern Distribution System Planning

Modern and future distribution planning deals with the same problems as conventional planning, grid upgrade/expansion to supply existing/new loads, as well as with new issues, specifically with: 1) the need to integrate DER, while meeting existing and new planning criteria, and 2) the identification of Non-Wire Alternatives (NWA) to complement or replace conventional solutions to address planning needs, such as capacity expansion/deferral, reliability and voltage regulation improvement. Load growth is driven by new customers, which is a common element with traditional planning, and by new types of loads, such as electric transportation, which requires, for instance, analyzing charging patterns and their impacts on grid infrastructure. DER integration is probably the area that poses the greatest challenges for distribution planning, given that distribution grids have not been designed to interconnect generation or energy storage facilities, and this can lead to a wide variety of impacts. Specifically, the Variable output nature of the most popular renewable DG technologies, such as solar photovoltaic (PV) and wind, can lead to the flow of electric power in more than one direction, i.e., from substations to end users, and also from end users to substations. Moreover, for large penetration levels of Variable DG, distribution feeders can essentially become active sources and inject power beyond distribution substations, into sub-transmission and transmission systems. The fact that PV and wind DG output Variability is a function of weather patterns and the introduction of energy storage and demand response into the mix, involves additional uncertainties that make modern and future distribution planning even more complex. For instance, while energy storage is in general an effective way to mitigate the effects of DG output Variability, its location, size and charging/discharging patterns need to be optimized to meet additional objectives, such as deferring infrastructure capital investments in capacity upgrades or expansions and making deployment justifiable from a financial and economic standpoint. Additionally, emerging applications of modern DG technologies that rely on smart inverter technology include the ability to provide ancillary services, e.g., help regulate grid voltage and frequency, and potentially support the operation of the grid during contingency conditions, including islanded microgrid operation. Modern and future distribution planning needs to consider all these aspects to optimize the design of the grid.

D.1.1 Overview of Present Activities of Distributed Energy Resources Integration in Distribution System Planning

The following are examples of key industry developments pertaining to DER integration and how they affect distribution systems planning:

- 1) **Hosting capacity:** Two important concepts requiring the study and understanding of DG impacts in distribution system are penetration level and hosting capacity. Penetration level is a measure of the balance between DG and load in a distribution feeder or substation; it is usually defined as the ratio between the installed capacity of DG

and the peak demand of the feeder or substation. Hosting capacity is usually defined as the maximum amount of DG that can be interconnected to a distribution feeder or substation without causing systemic violations of key operations and/or planning Variables, such as maximum voltage or equipment rating. It is worth noting that the severity of expected impacts increases as DG penetration levels grow and approach hosting capacity limits (under a constant hosting capacity scenario). Hosting capacity can be increased by implementation of mitigation measures, such as distribution system reinforcements and implementation of advanced solutions. The latter includes using smart inverters, whose voltage control capabilities allow issues caused by DG interconnection to be alleviated, as shown in Figure 24.

- 2) [Load and DER forecasting](#): Load forecasting is one of the key building blocks of traditional distribution planning, and will remain a vital component of modern and future distribution planning. Key developments in this area include the availability of high granularity spatial and temporal data, which will be provided by Advanced Metering Infrastructures (AMI), distribution automation solutions, and advanced sensors. Furthermore, as utilization of smart inverters and electric vehicle adoption increases, the impact of implementing advanced functions of smart inverters (e.g., implementation of active power curtailment or Volt/Watt function) will require both, updating load forecasting methodologies and developing more accurate DER and weather forecasting approaches.
- 3) [Peak and multi-hour capacity planning](#): The implementation of active power curtailment (Volt/Watt function) on a fleet of PV plants with smart inverters can change feeder load profiles, making it more difficult to estimate “true” customer loads already masked by DER proliferation, and create locational issues. Therefore, performance evaluation and capacity planning of modern distribution systems requires studying a Variety of multi-hour scenarios, not only peak loading conditions. Moreover, aspects that were not traditionally taken into account in planning studies, such as the availability and firm capacity contribution from DER units, or the spatial effect of DER output, must now be considered. Therefore, it is necessary to revisit and update existing planning methodologies, practices, tools, and procedures and adapt them to this new reality.
- 4) [Joint T&D systems planning](#): As distribution systems evolve from largely radial passive systems into more complex dynamic grids, the boundaries between transmission and distribution system engineering are starting to blur and lead to the emergence of joint T&D systems analysis, planning, operations and engineering. For instance, in the specific case of planning, there is growing interest in understanding the contribution to power system adequacy of Variable DG interconnected to distribution systems, e.g., wind and solar. This includes understanding how power system adequacy may be affected not only by Variable DG output changes driven by seasonal weather patterns, or transmission line outages, but also by distribution system reliability and the utilization of emerging solutions, such as combined Variable DG and energy storage applications. As the interactions and interdependencies between T&D systems grow, it is expected that new planning issues such as this one will arise, along with the need for new techniques and methodologies to solve them. Moreover, new areas, such as distribution operations planning, are also likely to emerge and evolve into standard T&D systems activities.

Figure 24 shows an example of benefits of using smart inverters to mitigate impacts caused by PV proliferation (over 5 MW). Voltage profiles before adding PV plant (top-left), after adding PV plant operating at unity power factor (top-right), and after setting PV plant to absorb reactive power (bottom) using advanced inverters (operation at 0.99 constant power

factor). Each dot is the voltage magnitude (PU) of a feeder node (miles from substation) at a specific time of the day (24 hrs.) for the respective cases (base, PV at unity power factor, and PV absorbing reactive power at 0.99 power factor) [45].

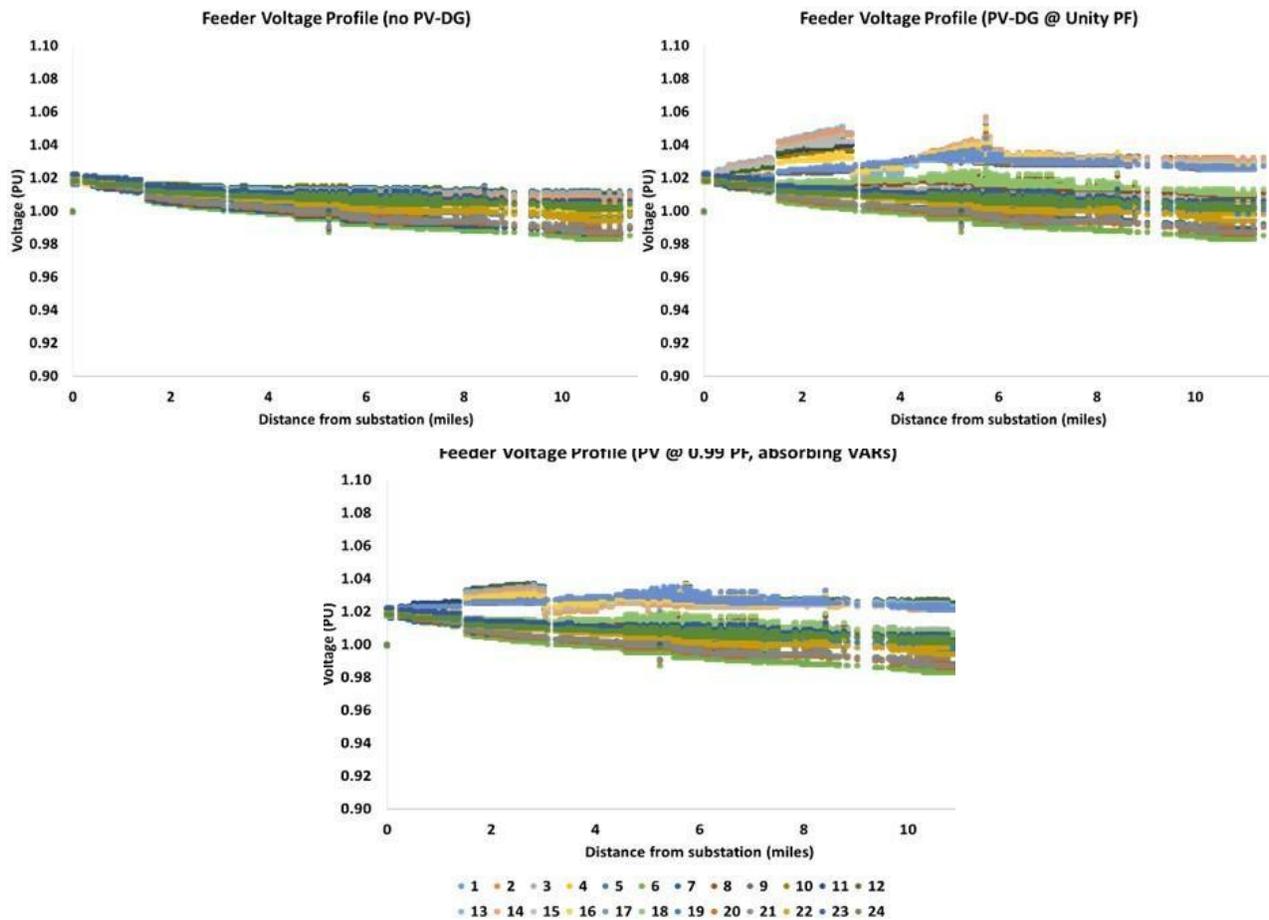


Figure 24. Benefits of using smart inverters to mitigate impacts caused by PV proliferation.

- 1) **DER integration:** In order to integrate DER into the distribution planning process it is necessary to have awareness over new interconnection requests and related data. This is analogous to new customer connections and commercial and industrial customer inquiries in traditional systems. As DER increases and becomes ubiquitous, it will be vital to automatically update information systems and software tools with the information that is needed to integrate new DER facilities and conduct pertinent planning studies, e.g., settings of smart inverters. These processes will require computational models of distribution feeders to be updated automatically and periodically with the needed information to reflect the interconnection of new DER.

- 2) [Advanced distribution modeling and analysis](#): Studying dynamic and active distribution systems implies using more detailed computational models and conducting sophisticated analyses, which requires having grid analytics solutions in place. Examples include dynamic analyses of distribution feeders to assess potential impacts of switching operations on DER performance, contingency analyses of distribution feeders to evaluate potential interactions between DER and distribution automation schemes, or evaluation of benefits of deploying DES solutions. Most popular software solutions for distribution system analysis include capabilities to model smart inverter functions, e.g., Volt/VAr and Volt/Watt, however, more work is needed to validate the accuracy of these models with respect to real system performance.
- 3) [Locational value of DER](#): DER adoption and smart inverters may provide benefits to the electric power delivery system and to end users. These benefits must be estimated and taken into account to evaluate the feasibility of using DER as an alternative to address system needs versus traditional distribution planning solutions. These benefits are highly dependent on DER technology, penetration level, and point of interconnection location, as well as on hosting grid characteristics. Estimating the locational value of DER is a complex endeavor, since it needs to account for quantitative (hard) and qualitative (soft) benefits of DER. Understanding the locational value of DER is an important aspect of the distribution system and utility of the future that will allow not only an efficient integrated planning of the grid, but also the fair compensation of DER and allocation of benefits to customers.
- 4) [Microgrids](#): There is growing interest in the industry in the application of microgrids to take advantage of the proliferation of DER to address planning objectives such as improving resiliency and efficiency. Examples of the Various types of potential microgrid types are shown in Figure 25; these configurations can provide service to a single customer, e.g., a residential microgrid (also known as nanogrid) or a campus microgrid, or to a group of customers, e.g., secondary microgrid, partial and full feeder microgrids, and substation microgrids. Microgrids are an important component of the distribution system of the future, particularly to improve the resiliency of critical loads. The advanced control capabilities of smart inverters (e.g., voltage and frequency control) are expected to play a critical role in enabling the implementation of microgrids.

D.1.2 Potential Impacts and Challenges on Distribution System Planning Brought by Implementing Smart Inverter Functions

This section presents the related smart inverter functions regarding DER integration and their potential impacts.

D.1.2.1 Potential Impacts and Challenges on Smart Inverter Functions for Voltage and Reactive Power Control

Integration of DER may change feeder voltage profiles, as well as lead to voltage increase and potential voltage violations, particularly at the point of interconnection. The output of Variable DER (PV and wind) can change significantly due to external conditions such as cloud movement and wind speed Variations; this can modify feeder power flows, voltage drops and lead to voltage fluctuation that may affect quality of service and generate complaints from customers. Therefore, several smart inverter functions, such as Constant power factor, Volt/VAr, etc., have been required as part of new and emerging interconnection standards such as IEEE 1547-2018, California Rule 21 and Hawaii Rule 14 to mitigate the above-

mentioned impacts from the Variable DER plants. However, choosing the optimal activation status and default settings of these functions is a challenge, which may bring significant impacts on the utility distribution system.

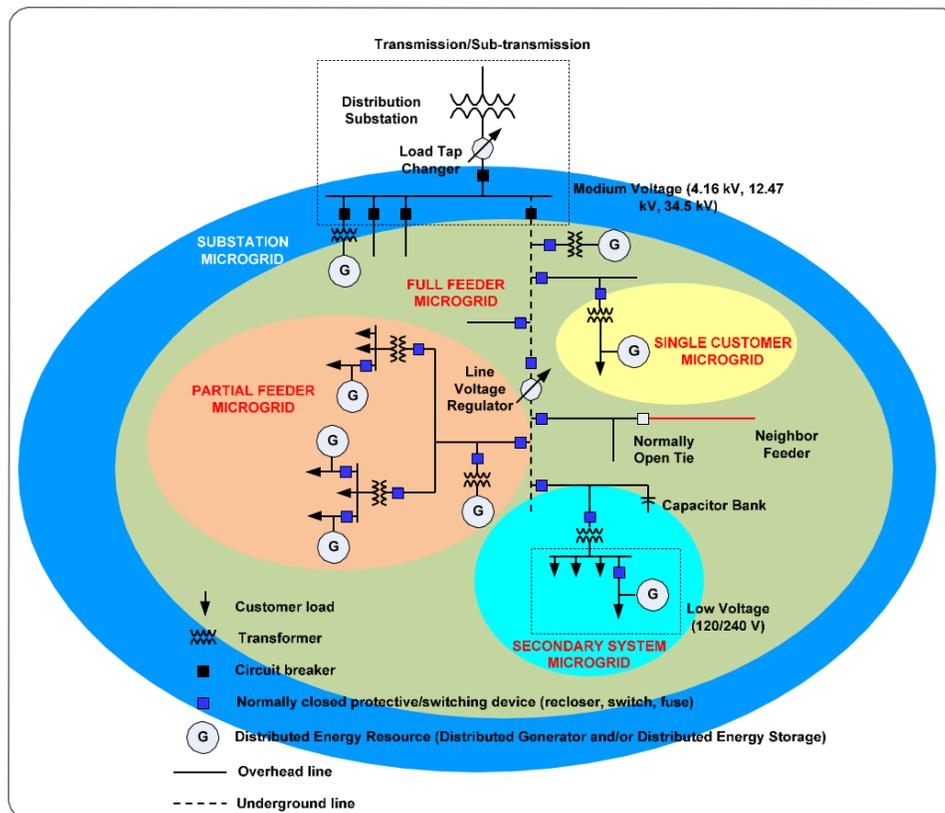


Figure 25. Conceptual examples of microgrid configurations: single customer, secondary system, partial feeder, feeder, and substation microgrids [46].

As described in the standards, voltage and reactive power control functions are mutually exclusive, meaning the DER can activate only one of these modes at a time. As shown in Table 5, IEEE 1547-2018 requires Constant power factor mode with unity power factor setting as default mode unless otherwise specified by the Area EPS operator. The Voltage-reactive power mode is required as reactive power priority, although it is deactivated as default. California Rule 21 requires Voltage-reactive power mode as default with real power priority unless otherwise provided by the Distribution Provider. Hawaii Rule 14 previously required Constant power factor with 0.95 absorbing but recently changed to Voltage-reactive power mode with reactive power priority. Although these functions are all for reactive power control, it brings the implementation challenge of understanding the impacts and choosing the default mode and settings.

Table 5 Smart Inverter Functions for Voltage and Reactive Power Control in Different Standards

Standards	IEEE 1547-2018	California Rule 21 (phase 1)	Hawaii Rule 14
Required control modes	<ul style="list-style-type: none"> • Constant power factor • Voltage-reactive power (with reactive power priority) • Active power-reactive power • Constant reactive power mode 	<ul style="list-style-type: none"> • Constant power factor • Voltage-reactive power (with real power priority) • Frequency-Watt (Optional) 	<ul style="list-style-type: none"> • Constant power factor • Voltage-reactive power (with reactive power priority) • Frequency-Watt
Default activation mode	<ul style="list-style-type: none"> • Constant power factor mode with unity power factor setting shall be the default mode of the installed DER unless otherwise specified by the Area EPS operator 	<ul style="list-style-type: none"> • Voltage-reactive power (with real power priority) unless otherwise provided by Distribution Provider 	<ul style="list-style-type: none"> • Voltage-reactive power (with reactive power priority) or upon mutual agreement between the Customer-Generator and the Company.

As shown above, the default mode is either Constant power factor or Voltage-reactive power mode. The Constant power factor mode sets all the smart inverters to a constant power factor value. If unity power factor is specified, there will be no reactive power injected or absorbed by the Smart Inverter to the grid, which means no capability to mitigate the voltage problems. If the non-unity power factor is required, such as 0.95 lagging power factor, the inverter will always provide reactive power to the grid even when the voltage is close to the nominal voltage and curtailment of active power may be needed when the solar plant is producing at high output levels. The curtailment will be dependent on the DER output, Power factor setting, and how the inverter is sized proportionally to the size of the DC plant.

Voltage-reactive power mode actively controls the reactive power output as a function of voltage at the PCC. Based on the set points, it provides the voltage control in both over-voltage and under voltage scenarios by absorbing or injecting reactive power respectively. There will be no reactive power injected when the voltage is within a certain voltage range (dead-band) that is close to the nominal voltage or reference voltage. An inverter with Voltage-reactive power mode could have either a real power priority (P priority) or a reactive power priority (Q priority). Each inverter has a maximum capacity (name-plate capacity). In situations where an inverter must make a choice between providing solely real power and curtailing some real power to provide/consume reactive power, the mentioned P priorities and Q priorities come into picture as follows:

- P priority: provide solely real power
- Q priority: curtail some real power to provide/consume reactive power.

When the inverter is not operating at its full capacity, there is no need for a power priority to be set as the inverter does not have to reduce its real power to provide/consume reactive power for voltage regulation [47]. When the maximum capacity has been reached with all active power out, inverters with the P priority will not provide any voltage control. However, in this scenario, inverters with the Q priority will still provide reactive power for voltage control by curtailing a minimum amount of the real power. The amount of curtailment will depend on the sizing of the smart inverter with respect to DC plant, inverter set points, operating voltage, and corresponding reactive power absorption/injection set point.

The different impacts with pros and cons of these modes have been compared and listed in Table 6. Therefore, different default functions and settings will have different impacts on the systems. The standards provide high level requirements about the required functions and settings with default mode. It also allows utilities to specify the default functions and settings which may be different. Further studies may be needed for analyzing different impacts on specific feeders with historical data.

Table 6 Comparison Between Different Smart Inverter Functions for Voltage and Reactive Control

	Volt/VAR with Reactive Power Priority (Q-Priority)	Volt/VAR with Real Power Priority (P-Priority)	Constant Power Factor (CPF)
Description	<ul style="list-style-type: none"> Inverter can provide reactive power support at all output levels of the solar plant, and may require curtailment of real power output to do so 	<ul style="list-style-type: none"> Inverter can provide reactive power support only when the real power output from the solar panels is less than the rated capacity of the inverter 	<ul style="list-style-type: none"> Inverter injects/absorbs reactive power based on ratio established by the power factor setting at all generation output levels
Pros	<ul style="list-style-type: none"> Can increase feeder hosting capacity Can reduce grid integration cost in certain situations IEEE 1547-2018 Volt/VAR setting has Q priority Hawaii and Europe require Q priority for Volt/VAR CPUC issued a proposed order to change to Q priority with all three IOUs' support Most inverters can meet this requirement 	<ul style="list-style-type: none"> Can mitigate voltage impacts of DER when inverter has enough capacity Inverter would not curtail real power to produce reactive power Default as existing CA Rule 21 settings Available in the market as mature products 	<ul style="list-style-type: none"> If set at unity, no real power curtailment is needed IEEE 1547-2018 has constant power factor mode as default activated Easy to implement
Cons	<ul style="list-style-type: none"> Need to curtail real power output to produce reactive power in certain conditions (only when inverters operating at 100% of real power output and voltage outside of dead-band) 	<ul style="list-style-type: none"> Not able to mitigate voltage impacts of DER if the inverter does not have enough capacity (e.g., inverter at full real power output) For hosting capacity, worst case (no reactive power absorption) must be studied – could limit the amount of DG a feeder can host CPUC issued a proposed order to change to Q priority with all three CA IOUs' support 	<ul style="list-style-type: none"> Does not mitigate voltage impacts of DER if set at unity Potentially limiting factor on feeder hosting capacity May need to be changed to non-unity power factor if interconnection causes problems If set at outside of unity, curtailment needed for real power

D.1.2.2 Potential Impacts on Existing Voltage Optimization Schemes, Coordination with Existing Devices, Such as LTCs, Capacitor Banks

The distribution system voltage is often regulated and controlled by transformer load tap changers, voltage regulators and switched capacitors for Various load levels. These devices are strategically located, tuned, and programmed to maintain

voltage at appropriate levels. The interconnection of DER may alter existing distribution circuits' loading patterns during generation thus altering the performance of present voltage regulation devices. Regulation devices were set to correct voltage drop due to radial load flow but DERs may have to be studied and potentially relocated, reprogrammed, retuned, and/or eliminated to accommodate DERs. Voltage fluctuations caused by Variability of DER can lead to frequent operation of voltage regulation and control equipment; the incremental wear and tear associated with these additional operations may imply more frequent maintenance needs and costs for utilities eventually impacting equipment life cycle. In addition, if the existing systems have conservation voltage reduction (CVR) schemes, the inverters may bring up the voltage affecting the results [48]. Reference [15] presents some detailed studies on the Hawaii and PG&E systems. Results show that the smart inverter Voltage-reactive control with suitable settings can help mitigate impacts to CVR to increase the energy savings for CVR schemes with high DER penetrations which would otherwise be impacted by the voltage rise caused by the DERs.

It is noted that the existing requirements in the standards are for the smart inverters' capabilities. The above-mentioned interaction between inverters and other voltage regulation devices needs to be further analyzed. Therefore, detailed impact studies, such as interconnection studies required by utilities, are essential to provide analysis for DER integration. If the results show that, in certain situations, the default settings of the inverter may cause problems on the system, these settings need to be modified for those specific interconnections.

D.1.2.3 Potential Impacts on the Hosting Capacity of Distribution Systems

The hosting capacity of the grid is the amount of new production or new consumption that can be connected without adversely impacting the reliability or power quality for other distribution system users. Hosting capacity can not only be calculated for individual locations but also for larger areas or even for a large interconnected system. The hosting capacity challenge is dependent on the location of the new production, the state of the distribution grid and its operation and control characteristics. One phenomenon that often limits hosting capacity is over-voltage due to the voltage ride or reduction in voltage drop when injecting active power to the distribution grid and thermal overloads due to increased power flow exceeding the transfer capacity of cables, lines, or transformers.

As mentioned before, the smart inverter functions can help mitigate the unacceptable voltage impact by providing reactive power controls. Therefore, these functions may have impacts on the feeders' hosting capacity. Studies from EPRI evaluated effects of smart inverter functions, including Constant power factor and Voltage-reactive power control, on hosting capacity on feeders in New York Distribution Systems [49]. Sandia National Laboratory also conducted studies on improving distribution network PV hosting capacity via smart inverter reactive power support [50]. Results from both studies show that smart inverter functions can increase the hosting capacity effectively by providing appropriate reactive power absorption.

It is noted that actual increase of hosting capacity depends on many factors like feeder voltage profile, distance of DER from the substation, size of the DER and voltage regulator deviations. In addition, with the implementation of the smart inverter standards, smart inverter functions shall also be considered when analyzing the hosting capacity of the distribution systems.

D.1.2.4 Parallel Operation of Multiple Smart Inverters in Close Proximity and with Similar Settings

To study the voltage fluctuations in distribution systems under high DER penetration levels, it is important to consider the impact that the reactive power control schemes at multiple inverters may have to the overall voltage profile of distribution feeders. It is also important to consider which inverters may contribute to voltage controls and at which levels. Of particular interest is operation of multiple inverters in different feeder locations with the same settings.

A recent paper by EPRI [51] concluded the following on the interactions between such inverters: “The simulation results show that there can be interaction with two large inverters located electrically close to one another. The parameters of Volt/VAr settings, the inverter controller parameters and the voltage averaging window can cause more/less oscillations. Results seem to indicate that aggressive Volt/VAr slopes (high sensitivity of reactive power with respect to voltage deviation) and fast-response times tend to cause the inverters to interact more significantly. Results also seem to indicate that averaging terminal voltages can damp oscillations but it may introduce larger voltage fluctuation initially and may be undesirable in terms of slowing the reactive power response time of the inverters.” And “Slightly asynchronous operation could reduce the interactions.” These interesting results bring about the topic of how multiple smart inverters with similar settings will impact system performance. With high penetration of DERs in the future, parallel operation of multiple smart inverters with similar settings shall be studied in the distribution planning.

D.1.2.5 Challenge on the Existing Planning Tools to Include Smart Inverter Functions

To provide detailed analysis on impacts of different smart inverter functions, the simulation software used now for the distribution planning shall be upgraded to include the models of the smart inverters with different smart functions required by standards. In addition, the smart inverter models in the software should allow users to define different default modes with different settings, which can provide more flexibility to analyze different impacts. So far, most existing market available software have limited capabilities of modeling smart inverter functions, which will be an important module for the future distribution planning tools. In addition, hardware test beds such as Hardware-in-loop test beds are beneficial to test the smart inverter functions with different vendors and determine how they will interact before field deployment.



Appendix E — IEEE 1547 Communications Requirements Overview

E.1 Communications

E.1.1 Background

The IEEE 1547 revision states, “A DER shall have provisions for a local DER interface capable of communicating (local DER communication interface) to support the information exchange requirements specified in this standard for all applicable functions that are supported in the DER. Under mutual agreement between the Area EPS Operator and DER Operator additional communication capabilities are allowed. The decision to use the local DER communication interface or to deploy a communication system shall be determined by the Area EPS operator.”

It goes on to state, “For information interoperability, these communication capabilities shall use a unified information model, and non-proprietary protocol encodings based on international standards or open industry specifications.”

In section 10 of IEEE 1547-2018, the detailed data requirements are identified for each power system function defined in other sections. These are categorized into 4 groups:

- 1) [Nameplate Information](#) — This information is indicative of the as-built characteristics of the DER.
- 2) [Configuration Information](#) — This information is indicative of the present capacity and ability of the DER to perform functions which may change based on relatively static configurations or may reflect dynamic weather or electrical conditions.
- 3) [Monitoring Information](#) — This information is indicative of the present operating conditions of the DER, typically status data, active and reactive power output, but also what functions are active.
- 4) [Management Information](#) — This information is used to update functional and mode settings for the DER, thus allowing new settings and the enabling/disabling of functions.

These data requirements are described in a generic manner so that they are not associated with any specific protocol or communication configuration.

E.1.2 Communications Protocols: Capabilities, Pros, and Cons

In IEEE 1547, the DER must support at least one of the three protocols identified in section 10.7, namely:

- 1) SunSpec ModBus
- 2) IEEE 1815 (DNP3)
- 3) IEEE 2030.5 (SEP2).

In addition, it is stated that standard protocol support requirement does not preclude the use of additional protocols such as the information model defined by IEC 61850-7-420 using the IEC 61850-8-1 (MMS) or IEC 61850-8-2 (XMPP) protocols, or alternatively, profiles of the IEC 61850-7-420 information model mapped to IEEE 1815 (DNP3) or to SunSpec Modbus.



However, it is very important to understand the capabilities, pros, and cons of each of these protocols.

- 1) [ModBus](#) is a protocol used by most DERs to exchange data very rapidly among their internal components, such as between the DER controller and the inverter, the PV panels, the battery, and internal meters, as well as to local plant energy management systems. Because each DER manufacturer has been defining its own proprietary version of ModBus, these implementations are not consistent nor interoperable. Therefore, SunSpec and other groups, such as the MESA Standards alliance, have developed “standardized” profiles of ModBus data points that can be used interoperably by different DER manufacturers. These are being updated to support the IEEE 1547 functions, based on the IEC 61850-7-420 information model.
- 2) [IEEE 1815 \(DNP3\)](#) is a SCADA protocol that is used by most North American utilities for rapid monitoring and control of utility equipment, including bulk power plants, and now utility-scale DERs such as very large energy storage systems. Since each utility has specified DNP3 uniquely for their own SCADA systems, until now there have not been any standard or interoperable DNP3 profiles. This was not a problem in the past since utilities only communicated with their own equipment. However, since DER manufacturers will need their DER systems to communicate with many different utilities and cannot afford to develop unique DNP3 solutions for each utility, the MESA alliance and EPRI have developed a standardized DNP3 profile, “*DNP Application Note AN2018: DNP3 Profile for Communications with Distributed Energy Resources (DERs)*” that was updated in parallel with the revision process of IEEE 1547, is mapped directly from the IEC 61850-7-420 information model (which has also been updated in parallel), and thus supports all of the IEEE 1547 interoperability requirements. Figure 26 shows examples of MESA / SunSpec ModBus profiles (gray) for internal components and a MESA / DNP3 profile for SCADA communications (orange) for IEEE 1547 functions.
- 3) [IEEE 2030.5 \(SEPV2\)](#) is a web-based protocol with its own DER information model, based originally on the IEC 61850-7-420 DER information model. This protocol was selected as the default protocol for California’s Rule 21 implementations for those interactions between utilities and aggregators or DERs that are more “loosely coupled” (DNP3 is still expected to be used for “tightly coupled” SCADA interactions requiring response times on the order of one second). These loosely coupled interactions will expect response times of 5–15 minutes or longer, and will be used primarily for establishing the settings for autonomous functions, for sending schedules of actions, and for monitoring periodic information from aggregators and groups of DERs. This protocol is currently being updated to meet the California Rule 21 requirements and is expected to be updated for the rest of the IEEE 1547 requirements.
- 4) [IEC 61850](#) has both the DER information model in IEC 61850-7-420, and two IEC 61850 standard protocols, IEC 61850-8-1 and IEC 61850-8-2. IEC 61850-7-420 has updated its information model to cover all of the IEEE 1547 (and European) grid code requirements and is going through the final review process before being issued by the IEC initially as a Committee Draft (CD) in early 2018. Of the two IEC 61850 protocols, IEC 61850-8-1 was designed for the extremely rapid (microsecond) interactions needed for protection and other functions in substation automation. The second protocol, IEC 61850-8-2, is web-based for “IoT” implementations, and uses the well-established IETF XMPP “chat” technology which can provide rapid (seconds) interactions with individual DERs as well as with aggregators, facilities, and groups of DERs.

Although it is not directly indicated as one of the mandatory protocols in IEEE 1547 at this time, IEC 61850 is expected to be used globally for DER interactions with utilities.

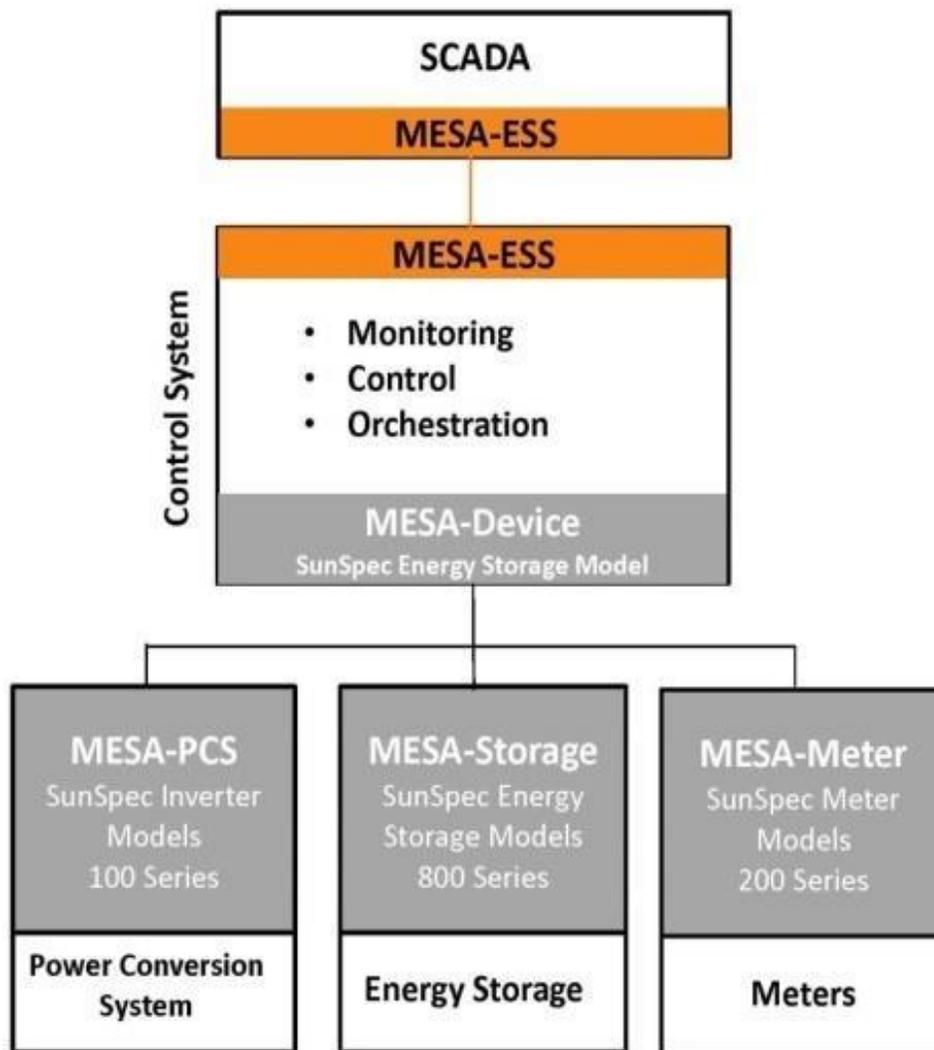


Figure 26. ModBus profiles (gray) and DNP3 profile for SCADA communications (orange).

E.1.3 Integration of IEEE 1547 DER Functions into Utility Operations

One of the big challenges for utilities is the integration of these IEEE 1547 DER functions into their existing operations. So long as DER system generation represented only a minor percentage of “normal loads” on feeders, they could be treated almost as negative load, but the rapid growth of photovoltaic, wind, and energy storage systems in all types of facilities (residential, commercial, industrial, microgrids, and power plants) is rapidly forcing changes to this simple approach.



For **utility-scale DER systems and plants**, utilities will often need to incorporate the management and monitoring of these DER directly into their distribution SCADA systems. In some cases, these larger DERs (possibly in aggregate) will bid into the bulk power energy market where they can use some of their DER functions for ancillary services such as automatic generation control and operational reserve. In other cases, they may have contracts or tariffs for providing some DER services to distribution operations, such as voltage support. In these situations, utilities will need to provide the value and timing parameters to the DERs and will need to carefully monitor the results. For example, utility-scale energy storage systems may be asked to counter excess reactive power that smaller PV systems have injected as they respond to voltage deviations with the IEEE 1547 Volt/VAR function.

Some utilities have developed **Distribution Management Systems (DMS)** for modeling and coordinating their utility distribution equipment, such as tap changes, capacitor banks, and voltage regulators. Now they will need to model groups of DERs along with the dynamic actions caused by their DER functions. In addition, since these DERs may be managed by different entities, such as aggregators, campuses, plants, communities, buildings, etc., the DMS will need to take into account the different tariffs, contracts, demand response agreements, and market actions, before it can communicate to each of these entities with the appropriate DER function requests, parameters, and schedules.

Utilities generally require a **DER database** and possibly a geographic information system (GIS) to identify at least the nameplate data and location of all DER systems within their territory. In the future, additional data in near-real-time could be used for short-term planning. This data, possibly part of a **DER management system (DERMS)**, could be used as input to state estimators and Various power flow applications which model and analyze the impact of the DER functions on the power system, and develop plans for utilizing these capabilities for reliability and efficiency purposes. DERMS are in their infancy in terms of defining and implementing DER capabilities. Eventually they could be used to determine what parameters, schedules, and other requirements should be communicated to different groups of DERs.

Once IEEE 1547 becomes mandatory in different jurisdictions, **DER functions will need to be metered** to ensure that each of the functions is operating correctly and at the right times. Therefore, metering, billing, and settlements will need to become more sophisticated for verifying these DER requirements are being met.

Long-term planning with DER will need to include dynamic assessment (including seasonal, weekly, daily, and even minute-by-minute) of the impact of large amounts of DER, including the impacts from generation, storage, controllable load (through demand response), and ancillary services. These assessments could allow utilities to defer new construction of traditional equipment. For these types of planning, more detailed data would need to be collected from key DERs over time.

E.1.4 Communication Configuration Issues

The protocol requirements in IEEE 1547 apply at the *local DER communication interface*, which is identified in Figure 27 as within the blue dotted area between the DER itself and any external network.

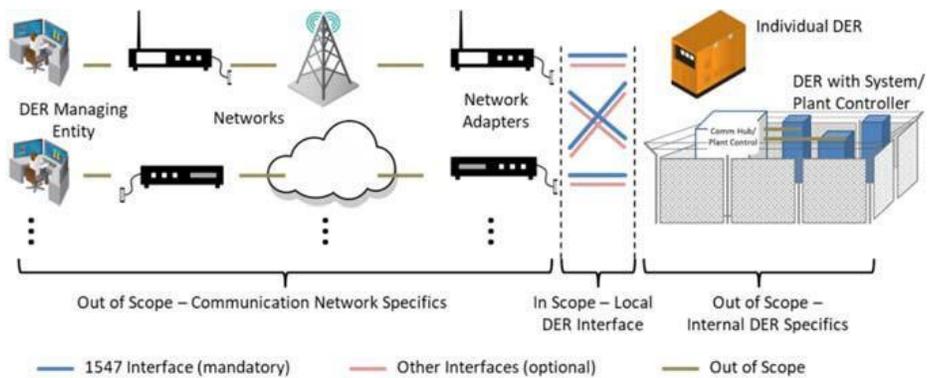


Figure 27. Scope of protocols defined in IEEE 1547.

The external communication network technologies and configurations are not addressed in IEEE 1547, but, as already ascertained in California, actual configurations of communication networks will need to be significantly different for different configurations of DERs: individual DERs, with facilities, and with aggregators (see some example configurations in Figure 28). Specifically:

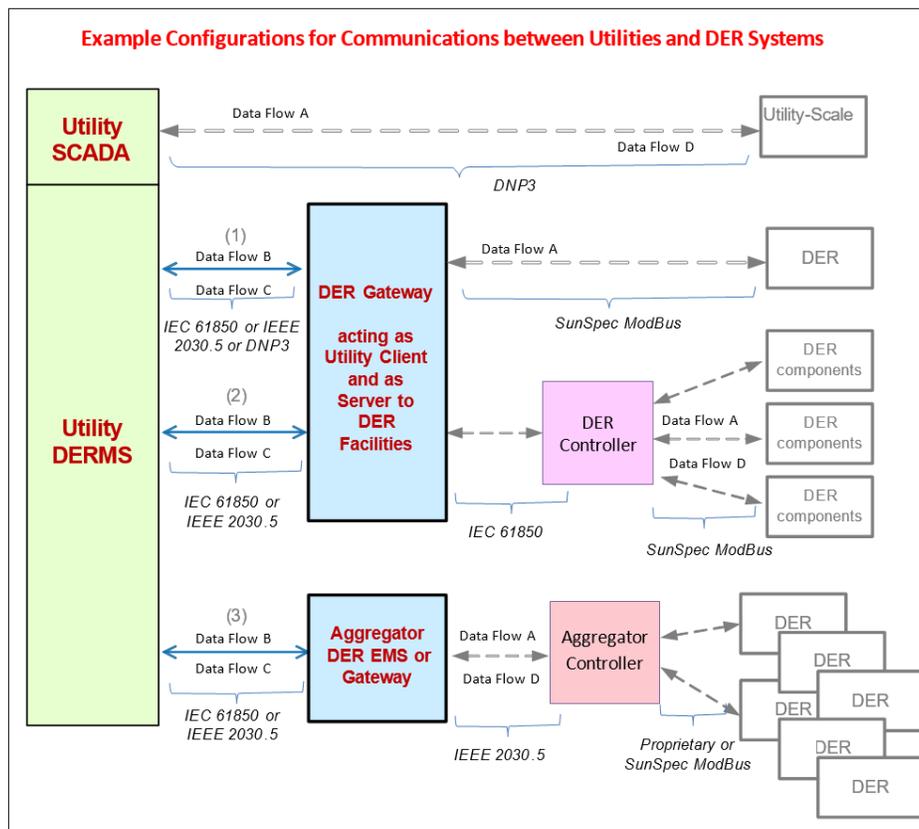


Figure 28. Examples of communication configurations for different protocols.

- 1) Communications between the utility SCADA system and the large DER units or plants for direct monitoring and control will most likely use IEEE 1815 (DNP3). This implies the need for reliable and secure communication networks even if the media itself may not be very secure. For instance, CAISO is considering the use of software-defined networks (SDN) which split messages into many parts and send them over multiple paths through the public Internet for increased reliability and security.
- 2) Communications between utility DERMS and DER controllers or aggregators will require gateways that could use SunSpec ModBus, DNP3, IEEE 2030.5, and/or IEC 61850. These gateways will act as firewalls, protocol translators, and client-servers as a way to decouple utility actions from DER actions for privacy and security purposes. The gateways could be provided by the utility or could be provided by third parties. The communication media may be the public Internet, private networks, cellular networks, or hybrid media. One possibility includes Advanced Metering Infrastructure (AMI) networks if these can meet the throughput and latency requirements.

E.1.5 Cybersecurity and Privacy Issues

IEEE 1547 does not directly address cybersecurity or privacy except to state, *“It is recognized that cybersecurity is a critically important issue for DER deployments connected to broader monitoring and control communications networks.”*

Cybersecurity for DER interfaces will need to be addressed as DERs are deployed. There are a number of cybersecurity standards and guidelines that could be used. The most pertinent to IEEE 1547 include:

- 1) [IEEE 1547.3: 2007](#): IEEE Guide for Monitoring, Information Exchange, and Control of Distributed Resources Interconnected with Electric Power Systems. This document should be updated since it is over 10 years old.
- 2) [ISO/IEC 27000 Series](#): Information technology — Security techniques. The key standards are ISO/IEC 27001, Describes requirements for information security management; ISO/IEC 27002, Code of practice for information security controls; and ISO/IEC TR 27019, *Information security management guidelines based on ISO/IEC 27002 for process control systems specific to the energy utility industry*.
- 3) [IEC 62443 Series \(based on ISA series of the same numbers\)](#): Security for industrial automation and control systems, including: IEC 62443-2-3: Patch management in the IACS environment; IEC 62443-3-2: Security risk assessment and system design; *IEC 62443-3-3: System security requirements and security levels*; and IEC 62443-4-1: Secure product development requirements.
- 4) [IEC 62351 Series](#): Power systems management and associated information exchange — Data and communications security. The series includes the cybersecurity requirements for IEEE 1815 and IEC 61850, as well as network security, role-based access control, and cryptographic key management standards. One technical report addresses DER security guidelines specifically: IEC/TR 62351-12: Resilience and security recommendations for power systems with distributed energy resources (DER) cyber-physical systems.
- 5) [NIST IR 7628](#): *Guidelines for Smart Grid Cybersecurity. In particular, Volume 1, Smart Grid Cybersecurity Strategy, Architecture, and High-Level Requirements provides a set of cybersecurity requirements that can be used as a checklist for DER developers and installers.*



- 6) NERC Critical Infrastructure Protection (CIPs): Cover the cybersecurity requirements for the bulk power system but may be pertinent for larger DER installations.

E.1.6 Future of DER Communications

The integration of DERs into the smart grid is causing a paradigm shift that affects all aspects of utility planning and operation. The management of these DERs is rapidly evolving and is becoming increasingly reliant on communications. The communication standards are being updated in almost real-time to try to meet the new requirements, but must still go through rigorous evaluation and testing, and so are often a few steps behind where they need to be to support, in this case, the new IEEE 1547 requirements. In addition, some details from IEEE 1547 will need additional clarification, such as what does the time delay in some functions really mean — is it to verify that frequency and/or voltage are stably within the normal ranges?

However, there is widespread industry commitment to provide the communications support as quickly as “reasonable”. In particular, it is clear that international standards for information models are critical for interoperability — without standardized “languages of verbs and nouns” for exchanging information, the result would be Towers of Babel, with misunderstandings and cyber vulnerabilities costing time and money. For this reason, it is envisioned that IEC 61850 as an information model will be indicated as the key requirement for interoperability. In addition, cybersecurity will become increasingly critical as the smart grid relies more and more on DERs for safe, reliable, and resilient operations.



Appendix F — Installation, Commissioning, and Periodic Testing

F.1 Commissioning and Testing of Interconnections

F.1.1 Introduction

The responsibilities, procedures, requirements, and criteria for the applicable test and verification methods are specified in IEEE P1547 standard. The stated verification requirements and test specifications are needed for interconnection of DER including static power inverters/converters.

The technical requirements specified in IEEE P1547 define the interconnection and interoperability requirements as well as verification process in accordance with the requirements identified in Clause 11 of IEEE P1547. This identifies the necessary conditions that need to be verified. These requirements include properties of the DER, properties that shall be maintained at operational interfaces, and properties that are needed throughout the life of the installed system.

All DER interconnection and interoperability requirements of this standard shall be demonstrated through either type tests, production tests, DER evaluation, commissioning tests, or periodic tests or a combination of these tests and verification methods.

The verification requirements for DER installation evaluation and commissioning testing are determined by whether the DER interconnection system has undergone full or partial conformance testing, and whether the DER system is interconnected at a point of common coupling (PCC) or a Point of DER connection (PoC).

F.1.2 Key Drivers of Verification Requirements

F.1.2.1 Reference Point of Applicability (RPA)

Specific designation of a reference point of applicability (RPA) is important in enabling smart inverter deployment. This method allows relatively small systems or systems that do not export significant power to the area EPS a designation that allows less verification after type testing. The default RPA is the point of common coupling (PCC): The point of connection between the Area EPS and the Local EPS.

Alternatively, the RPA for performance requirements of this standard may be the point of DER connection (PoC): The point where a DER unit is electrically connected in a Local EPS and meets the requirements of this standard exclusive of any load present in the respective part of the Local Area EPS.

This should be by agreement between the Area EPS Operator and the DER Operator, at any point between, or including, the PoC and PCC.

This decision depends on three criteria:

- Zero-sequence continuity (or not)
- Aggregate DER nameplate rating
- Annual average load demand.

F.1.2.2 Full or Partial Compliance

DER interconnection equipment or system is fully compliant if it does not require supplemental DER devices to meet IEEE 1547 requirements.

DER interconnection equipment or system that is in partial compliance requires supplemental DER devices to meet the requirements of IEEE P1547.

The test requirements give guidance, yet are flexible enough to consider the large Variety of actual DER setups in the field: A summary of the test requirements concept is described in Table 7.

Table 7 Summary of the Test Requirements Concept

IEEE P1547 Requirement XYZ		Applicability of Requirements	
		Point of DER Connection (PoC)	Point of Common Coupling (PCC)
DER Capability & Conformance achieved by	DER no Supplemental DER Device needed	Type Test of DER unit + Basic Commissioning Test ¹	Type Test of DER system + Basic DER Evaluation + Basic Commissioning Test ¹
	Composite one or more Supplemental DER Device(s) needed	Type Test of DER unit + Detailed DER Evaluation + Detailed Commissioning Test ¹	Type Test(s) of DER unit(s) + Detailed DER Evaluation + Detailed Commissioning Test ¹

Table Note:

1. A basic DER evaluation shall be limited to verify that the DER has been designed and installed with the proper components and connections. A detailed DER evaluation shall include an engineering verification of the chosen components and may require modeling and simulation of the composite of the individual partially compliant DERs forming a system.



F.1.3 DER System Verification Process

The IEEE P1547 standard outlines a process for verification that depends on type testing production testing, and whether the system-level type test indicates that it predicts system compliance to the interconnection standards. The design evaluation (desk study) is an evaluation during the interconnection review process to verify that the composite of the individual partially compliant DERs forming a system as designed meets the interconnection and interoperability requirements of this standard. This evaluation is usually done off-site before equipment is delivered and installed.

F.1.4 Component Level Verification

F.1.4.1 Type Testing

Type tests are performed on representative Smart Inverter Units or systems. This is usually done in a test lab, factory, or on equipment in the field. A type test needs to be performed on a DER within a product family of the same design and is allowed a range of power ratings between 50% and 200% of the tested system. The field demonstration of performance is agreed upon by the EPS and DER operators.

F.1.4.2 Production Testing

Production tests are tests on every unit of DER and interconnection prior to customer delivery to verify the operability of the unit or system. A summary report is provided with listed details required in IEEE P1547.

F.1.4.3 DER System Verification

1) DER as-built installation evaluation (on-site)

The as-built installation evaluation (on-site) is an evaluation at the time of commissioning to verify that the composite of the individual partially compliant DERs forming a system as delivered and installed meets the interconnection and interoperability requirements of this standard. This evaluation does not require testing.

2) Basic and detailed DER evaluation

A basic DER evaluation shall be limited to verify that the DER has been designed and installed with the proper components and connections. A detailed DER evaluation shall include an engineering verification of the chosen components and may require modeling and simulation of the composite of the individual partially compliant DERs forming a system.

3) Commissioning tests and verifications

Commissioning tests are tests and verifications on one device or combination of devices forming a system to confirm that the system as designed, delivered and installed meets the interconnection and interoperability requirements of this standard.

All commissioning tests shall be performed based on written test procedures. Test procedures are provided by equipment manufacturer(s) or system designer(s) and approved by the equipment owner and Area EPS Operator. Commissioning tests shall include visual inspections and may include, as applicable, operability and functional performance test.

4) Basic and detailed functional commissioning test

A basic functional commissioning test includes visual inspection and an operability test on the isolation device. A detailed functional commissioning test shall include a basic functional test and functional tests to verify interoperability of a combination of devices forming a system to verify that the devices are able to operate together as a system. The summary of the high-level test and verification process is described in Table 8.

Table 8 Summary of the High-Level Test and Verification Process

	Description
Type Test(s) of DER unit(s)	A DER unit that is type tested and compliant with the standard.
Type Test of DER System	A DER system that is composed of DER units that are type tested and supplemental DER devices.
Basic DER Evaluation	A basic DER evaluation shall be limited to verify that the DER has been designed and installed with the proper components and connections.
Detailed DER Evaluation	A detailed DER evaluation shall include an engineering verification of the chosen components and may require modeling and simulation of the composite of the individual partially compliant DERs forming a system.
Basic Commissioning Test	A basic functional commissioning test includes visual inspection and an operability test on the isolation device. ¹
Detailed Commissioning Test	A detailed functional commissioning test shall include a basic functional test and functional tests to verify interoperability of a combination of devices forming a system to verify that the devices are able to operate together as a system. ¹

Table Note:

1. A basic functional commissioning test includes visual inspection and an operability test on the isolation device.

The test and verification process for systems outline with the RPA at the PCC and PoC are depicted in Figures 29 and 30.

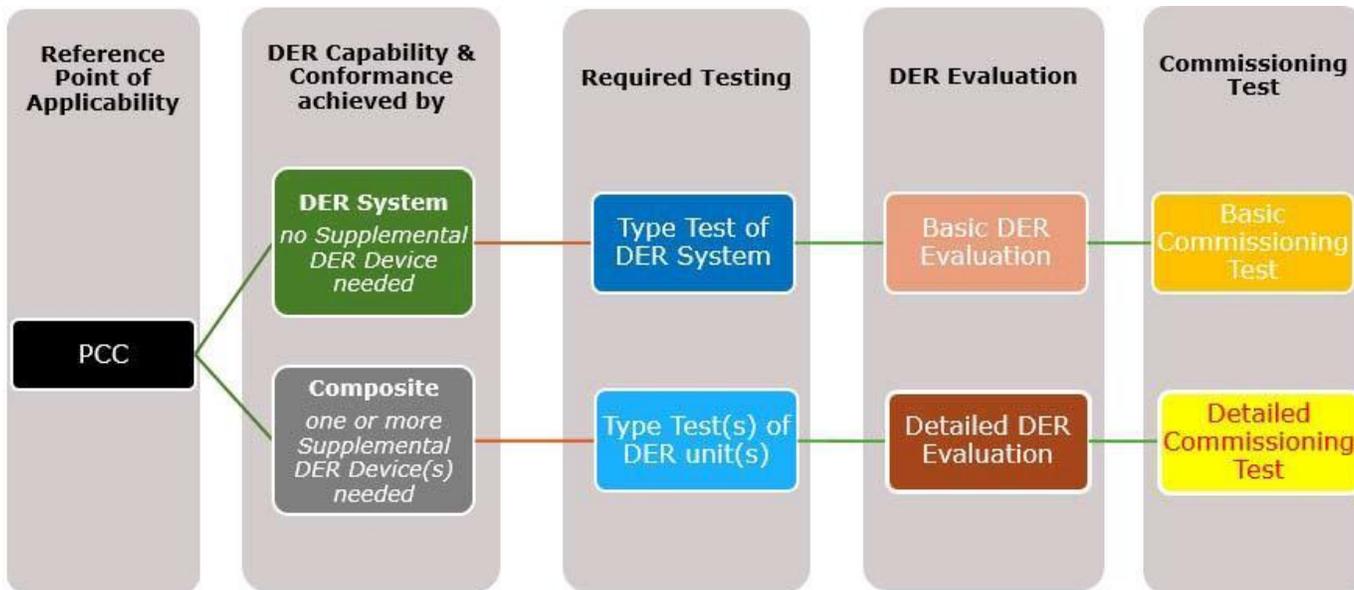


Figure 29. Test and verification process for systems outline with the RPA at the PCC.

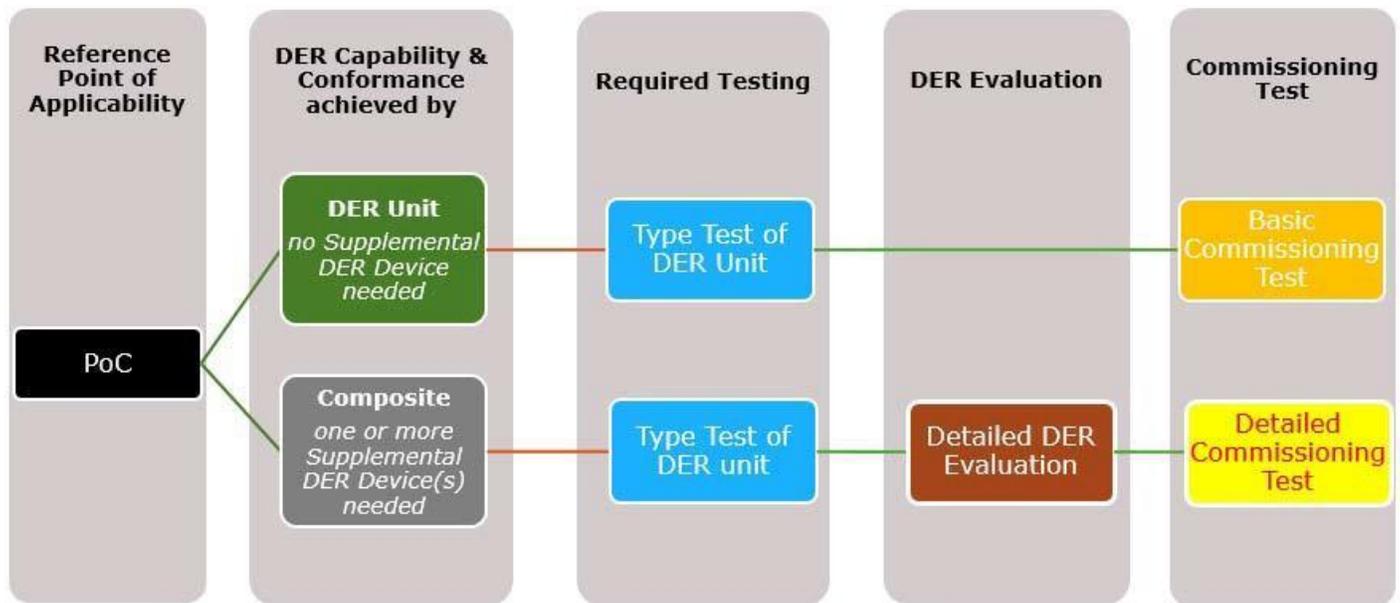


Figure 30. Test and verification process for systems outlined with the RPA at the PoC.

F.1.5 Commissioning Best Practices

The best practices described below will lead to optimized facility systems, increased energy efficiency and improved reliability and availability.

System testing is commonly undertaken at different levels during the commissioning of a facility depending on the critical nature of the equipment installed and the effect of downtime on the facility owner’s business. Additionally, testing is done on a recurring basis depending on the maintenance guidelines set by company policies, specific industries or regulatory agencies. Finally, testing is often done to validate corrective actions resulting from a facility power system failure or downtime of the facility owner’s business.

F.1.5.1 General

The commissioning process takes place in all phases of a project and should be planned as early as possible in the project. A clear definition of roles and responsibilities should be set before the project starts and refined at each phase of the project. All stakeholders should be involved in planning, including: owner’s facility management team, commissioning agent, equipment manufacturer, general contractor, and electrical contractor. Contingency plans should be included for project special circumstances that could affect timing of the commissioning.

The following summarizes best practices in each project phase:

1) Project planning phase

Pre-project development activities ensure that your commissioning plan and budget are included in the project development estimates along with organizational responsibilities. Agreements in place include:

- Develop commissioning plan with budget
- Ensure the plan comprehends Utility Commissioning Requirements
- Clarify roles and responsibilities for each phase
- Develop a commissioning checklist for the project.

2) Project design phase

During the design phase, ensure that the elements of the commissioning plan are included in the project and that design requirements specific to this project are included in the commissioning plan.

- Develop a written commissioning plan, including utility and supplier test requirements
- All parties involved should sign off on the commissioning plan prior to construction.

3) Project construction phase

During this phase, the equipment is installed and if required, the type test and approvals should be verified. Project schedule should be integrated and focused on timing for the final commissioning date.

- Factory acceptance testing is performed on critical subsystems such as disconnect device, inverter, HVAC
- Avoid duplication of tests (Suppliers performing design verification tests)
- A system test or production test should be performed at the subsystem level during the commissioning process.

4) Acceptance phase

The commissioning test is conducted once all equipment is installed as well as when the system goes live to verify correct operation.

- Testing of communication systems should be performed
- Acceptance testing can be completed under special circumstances that can affect timing; for example, when a substation is not energized or the utility wants to verify system protection behavior before connecting.

5) System handoff to operation

The requirements included in the commissioning test should flow into the maintenance plans that are put in place for the power system.

- The test data from the commissioning test can be used as a baseline for future testing of the system
- There should be a mechanism identified to identify and resolve post-commissioning issues.

6) Periodic tests and verifications

Periodic tests are tests and verifications, according to a scheduled time or other criteria, that confirm that one already interconnected device or combination of devices forming a system meets the interconnection and interoperability



requirements of this standard. Periodic test requirements and intervals for all interconnection-related protective functions and associated batteries shall be provided by interconnection equipment manufacturers or system integrators and approved by the AGIR or the Area EPS Operator. Frequency of retesting shall be determined by Area EPS Operator policies for protection system testing, or manufacturer requirements. Periodic test reports or a log for inspection shall be maintained.

The Area EPS Operator may require a commissioning test to be performed outside of the normal periodic testing to verify adherence to this standard at any time.

F.1.6 Installation, Commissioning, and Periodic Testing Summary

The discussion in this section focuses on the technical requirements for verification of operation of smart inverters. It does not specify the regulatory actions necessary or actions of other stakeholders such as NERC, Authorities Governing Interconnection Requirements, electric utilities, DER vendors and project developers. The requirements discussed define the interconnection and interoperability requirements as well as verification process in accordance with the requirements identified in Clause 11 of IEEE P1547. This identifies the necessary conditions that need to be verified. These requirements include properties of the DER, properties that shall be maintained at operational interfaces, and properties that are needed throughout the life of the installed system.

All DER interconnection and interoperability requirements of this standard shall be demonstrated through component-level verification through type tests and production tests. System-level verification includes, DER evaluation, commissioning tests, or periodic tests or a combination of these tests and verification methods. The Reference Point of Applicability (RPA) and Compliance with or without supplemental DER device(s) determines the verification requirements. More specifically, the requirements for DER installation evaluation and commissioning testing are determined by whether the DER interconnection system has undergone full or partial conformance testing, and whether the DER system is interconnected at a point of common coupling (PCC) or a Point of DER connection (PoC).

This process allows for small or simple systems to be verified without significant system evaluation or commissioning, relying on the type testing and production testing for this. It also requires more rigorous evaluation and commissioning for systems that may impact operation of the Area EPS.

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