ELECTRIC POWER RESEARCH INSTITUTE

“Enterprise” Technical Interconnection and Interoperability Requirements (TIIRs) for Distributed Energy Resources in the Tennessee Valley

“Enterprise” Technical Interconnection and Interoperability Requirements (TIIRs) for Distributed Energy Resources in the Tennessee Valley

Technical Update, September 2024

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ABSTRACT

This report provides a customizable template for developing or updating a local power company's technical interconnection and interoperability requirements (TIIR) for distributed energy resources (DER) on the distribution system. A TIIR document stipulates technical requirements in contrast to other utility DER documents or regulatory policies that, for example, specify the non-technical needs for an interconnection application and the technical review process. This "enterprise" TIIR document specifically presents a common set of technical requirements that can be issued by LPCs operating in the Tennessee Valley to DER customers, developers, and internal utility stakeholders.

The scope of this TIIR template encompasses DER interconnection requirements that are compliant with applicable standards, as well as other obligations for integrating DER into the utility's distribution system. Content includes:

- DER interconnection and interoperability capabilities and requirements,
- Functional settings specifications for applying DER capabilities,
- Stipulations for coordinating settings, voltage quality, system protection, and telemetry related to distribution operations,
- A "Technical Review Process" that includes generic DER technical review criteria for use when criteria are unavailable from the authority governing interconnection requirements (AGIR) and/or the responsible utility.

The structure and content of this document are derived from best practices accrued from reviews and revisions to multiple utility TIIRs, as well as collective insights gleaned from standards and certification development activities. Learnings distilled from the Tennessee Valley Authority's DER Interconnection Pilot (part of the Regional Grid Transformation initiative) have provided additional input.

Keywords

Technical Interconnection Requirements
Distributed Energy Resources
IEEE 1547-2018
Interconnection
Technical Review
DG Manual

FOREWORD

This report provides a customizable template for local power companies (LPCs) within the TVA region to apply towards the development of public-facing documents specifying the technical interconnection and interoperability requirements (TIIRs) for distributed energy resources (DER). To further inform development efforts, it also contains reference DER interconnection technical review criteria.

TIIRs describe the performance requirements of the DER plant as well as requirements for its compatible integration into the electric grid. The structure and content of this document leverages learnings gleaned from reviews of multiple utility TIIRs, recent DER field experiences, including those in areas with increasing DER deployment levels, and evolving standards development activities.

TIIR Scope

Figure ES-1 illustrates the scope of a TIIR document, which strongly emphasizes technical requirements and electric system compatibility (blue circles)—domains where the electric power system operator has authority. Technical requirements may be *informed by* company business processes or regulatory policies such as net metering tariffs, renewable energy credits, time-of-use rates, and other incentive or compensatory programs (brown circles), but generally such processes and policies are not published and maintained within the TIIR.

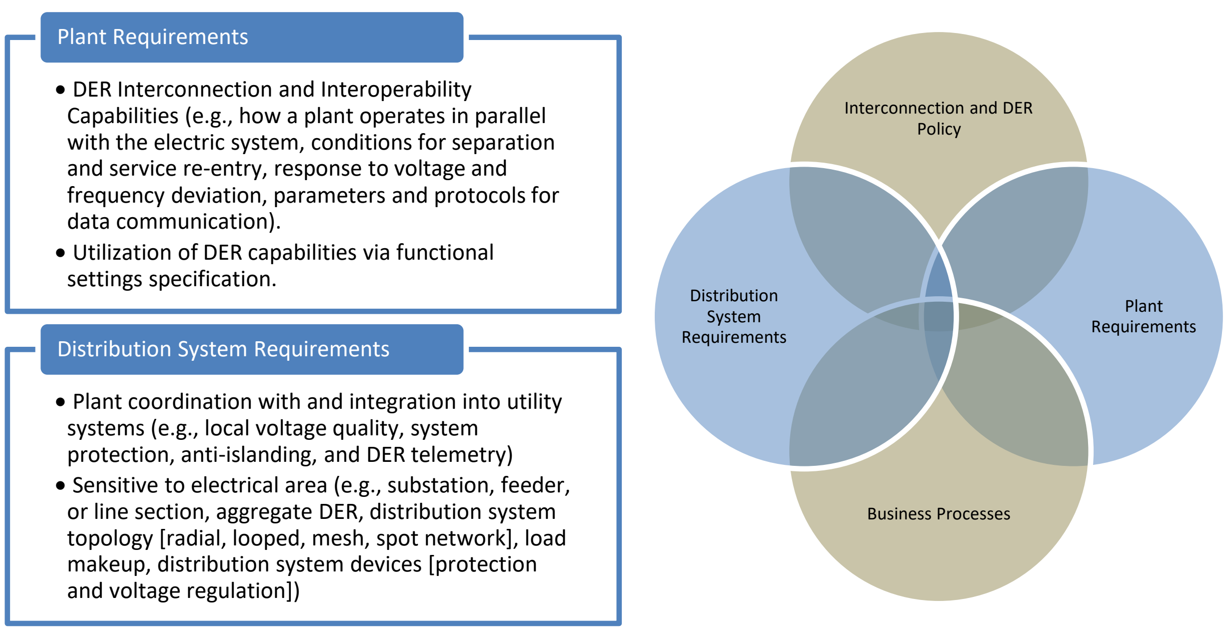

Figure ES-1
Technical Interconnection and Interoperability Requirements Scope

That said, utility industry TIIRs tend to vary in detail, length, and consistency of reference to IEEE 1547 interconnection standards. Practically, the TIIR serves to communicate requirements to all parties – principally DER customers, developers, and utility stakeholders – and to establish expectations for plant performance so that design and integration go smoothly. Yet, to date, there is no "one-size-fits-all" TIIR document that provides uniform guidance.

This TIIR template was designed to be a *detailed* reference, articulating requirements for plant and distribution system compatibility with a strong and consistent alignment with IEEE Std. 1547-2018, the primary standard governing the interconnection of DER on distribution in North America. It is intended to be functional and accurate "out of the box," but may not completely align with every LPC's DER integration engineering practice. Consequently, the TIIR template aims to provide flexibility to account for utility-specific practices and additional requirements that may go beyond IEEE 1547-2018 while maintaining consistency with the IEEE standards.

Ultimately, the adopting LPC has the burden to impose, verify, and enforce requirements placed on DER operating within its electric system. Stipulated clauses or sections in this TIIR template may be selectively modified or removed, and any regional technical requirements left unconsidered can be incorporated. At bottom, this report provides suggested requirements that LPCs can consider when developing or revising their territory-specific DER Technical Interconnection and Interoperability Requirements.

TIIR Project Context: The Regional Grid Transformation Initiative

The enterprise TIIR template presented in this report is an outgrowth of the DER Interconnection Standards Pilot, one of several projects housed under the TVA-LPC Regional Grid Transformation (RGT) initiative. Part of a broader effort to transform the shared TVA and LPC networks into an integrated, more resilient and flexible regional grid supportive to evolving customer needs, the DER Interconnection Standards Pilot was charged with helping to address the new challenges raised by increasing DER grid connections in the Valley. Activities, conducted over several years, produced a range of recommendations and accompanying best practice documentation for both aligning the interconnection processes of TVA with those of LPCs, and more generally standardizing associated practices throughout the Tennessee Valley.

A central emphasis of the pilot effort involved incorporating flexibility to accommodate LPC needs and circumstances while encouraging the adoption of a "Valley Standard" and regional consistency. To this end, the TIIR template and other pilot deliverables provide optionality to help support their adoption and use by LPCs throughout the Valley.

Integrating TIIR Flexibility to Meet Unique LPC Requirements and Operating Practices

LPC staff, member priorities, and business processes vary considerably throughout the Tennessee Valley. Some LPCs have a robust set of guidelines for interconnecting small and large DERs, while others embrace more informal procedures. Service areas with increased interconnection application volumes and relatively high DER penetrations often have application review protocols that impose greater scrutiny and procedural efficiency relative to other territories that receive only a handful of project applications per year. To simplify the process of developing LPC-specific TIIRs, EPRI recommends a modular adoption of the TIIR template to address specific or near-term business needs and technical gaps. Table ES-1 outlines some examples of modular TIIR implementation, but any combination or subset of TIIR chapters may be adapted to suit specific LPC needs.

Table ES-1
Modular Implementation Recipes

Focus Area, Implementation Need	Applicable TIIR Chapters	Description of Content
General DER Requirements	General Technical (4) DER Response to Abnormal Conditions (6) Power Quality (7)	*These chapters represent solid essentials for DER integration. They outline basic synchronization, cease-to-energize, tripping, and power quality considerations to set the standard that DER operating in parallel shall do no harm to the electric power system.*
Interconnection Process	Technical Review Process (3) Commissioning and Verification (10)	*For companies that have a good foundation for technical requirements but would like to establish more consistency in their review process. These chapters include steps on how to screen DER.*
DER Active-Reactive Power Modes	DER Support of Grid Voltage (5)	*Where an established DER practice is in place, and penetration is high enough to warrant mitigation, chapter 5 introduces the mechanism for enabling advanced DER features such as Volt-VAR and Volt-Watt modes.*
Distribution System Protection and Compatibility	General Technical (4) Islanding (8) Grid Compatibility (11)	*These chapters are used for the LPC to outline thermal limits, fault current limits, and to establish DER capacity thresholds where additional protection, DTT, or telemetry may be required.*
DER Communication / DERMS	Interoperability (9)	*Essential requirements for DER communication and control capabilities.*

Tailoring the TIIR Template

The TIIR template can be implemented in multiple, increasingly tailored ways. LPC adoption approaches can range from (1) verbatim, out-of-the-box, to (4) fully customized.

1. As-Is implementation consists of review and implementation of the largely unmodified TIIR template, with perhaps slight adjustments made to LPC business practices to align them with the processes and technical requirements detailed in the template.

2. A modular or chapter subset of the TIIR template may alternatively be adopted and integrated into existing LPC practices to strengthen under-specified interconnection requirement areas (as outlined in Table ES-1).

3. Specific parameters can be more granularly tailored when the structure and language within a TIIR chapter align with company practice but require additional engineering guidance. The TIIR template highlights variable fields using curly braces (e.g., {…}) to, for example, define values denoting allowable reverse power flow at the substation, service transformer operating ratings, DER fault current contribution, among others. Values are typically provided as a starting point for review, and LPCs may modify them based on unique company or regional practices.
4. Finally, every clause within the TIIR template is intended as a draft, and specific terms or additional details may be required to accurately articulate some requirements. LPCs have discretion to fully customize the TIIR's content, as appropriate.

In areas where the template offers options for content customization (indicated by curly brackets "{…}"), an LPC should insert its preferred language, as desired. Examples include specifications for DER performance category assignments, DER support of grid voltage, DER size limits subject to telemetry and control requirements, DER size limits where additional protection may be required, etc.

The following key clarifies the meaning of placeholders marked with braces, and the decisions the distribution utility should make when using this document:

- {UTILITY} Find all, and replace with LPC name
- {Text, Number or %} Select text or values, often a typical value is provided (note: the word "typically" is instructional and intended to be omitted for TIIR implementation).
- ***EPRI Note:*** *Consider this contextual commentary; it can be optionally removed when publishing the finalized, utility-specific TIIR.*

Establishing a Valley Standard

Although practices and technical requirements may vary across LPCs, TVA acknowledges value in LPC alignment and valley-wide standardization where possible. Use of the TIIR template as a framework to develop DER technical requirements provides a consistent starting point for discussion and consideration of various technical elements and simplifies the examination of regional differences. The adoption tactics described in this foreword are intended to enable pathways to Valley-wide consistency in DER integration.

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1 INTRODUCTION

1.1 Scope and Applicability

This Technical Interconnection and Interoperability Requirements (TIIR) document specifies technical requirements for interconnecting Distributed Energy Resources (DERs). DERs comprise generation and electric storage facilities that operate in parallel with and are capable of discharging power to the distribution grid of {UTILITY}. The purpose of these requirements is to maintain safety, reliability, and power quality of the distribution grid and service, and to protect utility and its customer assets. The requirements apply to all DER interconnections unless an exception has been granted by {UTILITY} to the Customer.

The document further provides criteria for Customers planning to interconnect DERs with the {UTILITY} distribution system. The utility distribution includes ac medium voltage (greater than 600 V to 50kV) and ac low voltage (less than or equal to 600 V) connections.

The document also addresses the responsibilities of the Customer related to grid integration, point of connection, and general DER system performance. It includes operational performance, power quality, protection, monitoring, control, and telemetry requirements. Interoperability with other grid equipment, metering requirements, as well as commissioning test and verification requirements are likewise addressed, as are specific operating requirements and any special protection that may be required for connections on radial or network locations in the distribution grid. The document further includes DER interconnection technical review criteria.

1.2 Adoption of IEEE 1547-2018

{UTILITY} has fully adopted IEEE 1547-2018[1], as corrected by errata for IEEE 1547-2018[2] and as amended by IEEE Std 1547a-2020[3], (hereafter: IEEE 1547-2018) for all DER interconnected to its distribution system. All DER interconnecting under these TIIRs shall meet requirements as specified in IEEE 1547-2018 and be tested, verified, or certified according to applicable standards. IEEE Std 1547-2018 clauses that are pertinent to sections in this document are identified throughout. Note that although some clauses are not identified in this document, the entirety of IEEE 1547-2018 has been adopted and is pertinent to the DER interconnection.

Requirements that are beyond the scope of IEEE 1547-2018 are also included in this document.

1.3 Effective Date and Grandfathering Clause

The requirements specified in this document shall apply to all DER interconnection request applications received after January 1, 2024. Any DER interconnections that are either already in

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

[2] https://standards.ieee.org/content/dam/ieee-standards/standards/web/documents/erratas/1547-2018_errata.pdf

[3] https://standards.ieee.org/standard/1547a-2020.html

operation or that have submitted their full applications prior to the above specified date, may continue to meet requirements as defined at that time. Existing DER interconnections that are substantially upgraded or changed may have to comply with the requirements specified in this document.

1.4 Responsibilities

1.4.1 Customer-Owned Generating Equipment

The Customer is responsible for designing, installing, operating, and maintaining its own equipment in accordance with interconnection agreements and applicable standards. The interconnection shall follow IEEE 1547-2018. Other applicable standards include, but are not limited to, the National Electrical Code (NEC), North American Electric Reliability Corporation (NERC) rules, applicable for independent system operators and regional transmission organizations, and all applicable laws, statutes, guidelines, and regulations. This includes installing, setting, and maintaining all protective devices necessary for safe grid integration and to protect the Customer's and utility's facilities.

Inverters shall be UL 1741 SB, or equivalent standards, certified as "Grid Support Interactive Inverter" or "Grid Support Utility Interactive Inverter" installed or commissioned with the IEEE 1547-2018 specified performance capabilities.

1.4.2 Utility Managed and Operated Distribution System

Requirements specified in these DER requirements are also intended to complement utility efforts and responsibilities to maintain distribution grid safety, power quality, and reliability. Continuity and quality of service to all customers is a key responsibility of the utility.

1.4.3 Responsibilities Related to Ongoing Utility Upgrades

The utility system is constantly changing due to shifts in loading, restoration, and the addition or removal of generation. The possibility exists that a change in the utility system may cause a change in the protection or other requirements at the generation interconnection. Any change in requirements will be communicated to the Customer. The Customer's responsibility for changes is spelled out in the interconnection agreement.

2

DEFINITIONS, ACRONYMS AND REFERENCES

2.1 Definitions

The terminology that is used in this document is intended to follow definitions and usage in IEEE Standard 1547-2018 and other related IEEE, IEC and ANSI standards. Several terms defined in IEEE 1547 standards are repeated here for convenience. In some cases, terms related to the Federal Energy Regulatory Commission's Small Generator Interconnection Procedures (FERC-SGIP) and related codes such as the U.S. National Electric Code, NFPA-70, are used in the context of those documents.

Selected definitions are provided in alphabetical order for convenience. Where appropriate, sources are noted in the text.

Abnormal: Term characterizing an event that results in electrical parameters deviating from normal steady state conditions causing undesirable conditions. The main electric characteristics are Voltage, Current, and Frequency.

Account: An account is one metered or un-metered rate or service classification which normally has one electric delivery point of service. Each account shall have only one electric service supplier providing full electric supply requirements for that account. A premise may have more than one account.

Area Electric Power System (Area EPS): The utility electric network, which includes public rights-of-way and extends across property boundaries.

Authority Governing Interconnection Requirements (AGIR): A cognizant and responsible entity that defines, codifies, communicates, administers, and enforces the policies and procedures for allowing electrical interconnection of DER to the Area EPS. This may be a regulatory agency, public utility commission, municipality, cooperative board of directors, etc. The degree of AGIR involvement will vary in scope of application and level of enforcement across jurisdictional boundaries. This authority may be delegated by the cognizant and responsible entity to the Area EPS operator or bulk power system operator.

Control Center: The EPS operator's facility that monitors and has direct control over the operation of the utility's Power Delivery System.

Customer: Any adult person, partnership, association, corporation, or other entity whose name is listed in a service account. A Customer includes anyone taking delivery service or combined electric supply and delivery service from the Company under one service classification for one account. The customer is also responsible for any DER connected to the electric system at the account.

DER Nameplate Rating: The sum of total maximum rated power output of all a DER's constituent generating units as identified on the manufacturer nameplate, regardless of whether it is limited by any approved means.[4]

Distributed Energy Resource (DER): A source of electric power that is not directly connected to the bulk power system. DER includes both generators and energy storage technologies capable of exporting active power to an EPS. An interconnection system or a supplemental DER device necessary for compliance with IEEE Std. 1547 is part of a DER. (IEEE 1547-2018.)

Energy Storage System (ESS): A system that has the mechanical, electrical, or electrochemical means to store and release electrical energy, and its associated interconnection and control equipment. An ESS is considered a DER that operates in parallel with the distribution system.

Export Capacity: The amount of power that can be transferred from the DER to the Distribution System. Export Capacity is either DER Nameplate Rating, or a lower amount if limited using acceptable means identified in chapter 11.

Facility (or Facilities): The Customer-owned DER equipment and all associated or ancillary equipment, including interconnection equipment, on the Customer's side of the Point of Common Coupling

Grid: The interconnected arrangement of lines, transformers, and generators that make up the electric power system. In this document, "grid" refers to the medium and low voltage portions of the electrical system.

Inadvertent Export: Unscheduled export of active power from an export-limited DER which exceeds a specified magnitude for a limited duration generally due to fluctuations in load-following behavior.

Interconnection Agreement(s): Any contract between EPS operator and one or more parties that outlines and governs the interconnection requirements of a generation facility.

Interconnection Equipment: That equipment necessary to safely interconnect the Facility to the utility's power delivery system, including all relaying, interrupting devices, metering or communication equipment needed to protect the facility and the utility power delivery system and to control and safely operate the facility in parallel with the utility power delivery system. (Adapted from IEEE Std 1547-2018.)

Limited Export: Exporting capability of a DER whose generating capacity is limited using any configuration or operating mode described in section 11.4.

Local DER communication interface: A local interface capable of communicating to support the information exchange requirements specified in this standard for all applicable functions that are supported in the DER. (IEEE Std 1547-2018.)

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[4] IREC, Toolkit & Guidance for the Interconnection of Energy Storage & Solar-Plus-Storage, DOE, 2022.

Microgrid Interconnect Device (MID): A device that enables a microgrid (intentional island) system to separate from and reconnect to operate in parallel with the area EPS.

North American Electric Reliability Corporation (NERC): The purpose of NERC is to ensure the adequacy, reliability, and security of the bulk electric supply systems through coordinated operations and planning of generation and transmission facilities.

Non-Export or Non-Exporting: DER sized, designed, and operated using any of the methods in chapter 11, such that the output can be used to serve the local EPS and no electrical energy (except inadvertent export) is transferred from the DER to the area EPS.

Operating Profile: The way the DER is designed to be operated, based on the generating prime mover, Operating Schedule, and the managed variation in output power or charging behavior. The Operating Profile includes any limitations set on power imported or exported at the Point of Common Coupling and the resource characteristics (e.g., solar output profile or ESS operation).

Operating Schedule: The time of year, time of month, or hours of the day designated in the Interconnection Application for a DER's power import or export.

Parallel Operation: Any electrical connection between the utility power delivery system and the customer's generation source.

Point of Common Coupling (PCC): The point where the customer system interconnects with the utility grid. It is the demarcation point between customer-owned equipment and utility-owned equipment. (Adapted from IEEE Std 154-2018.)

Point of DER Connection (PoC): The point where DER is electrically connected within a premise or electric network. Sometimes this point is also the PCC.

Power Control System (PCS): A systems or device which electronically limits or controls steady state currents to a programmable limit.

Revenue Metering: For the purposes of this document, revenue metering refers to the meter or meters used for kWh billing and production crediting as well as any instrument transformers, communications equipment, and wiring between these devices.

Reference Point of Applicability (RPA): The electrical location used to determine satisfactory DER performance. The RPA for any performance requirement varies and can be at the Point of Connection (PoC) or the Point of Common Coupling (PCC). DER Requirements in this TIIR document apply to the RPA. (IEEE Std 1547-2018; the location concept is defined in clause 4.2.)

RTU (Remote Terminal Unit): The remote unit of a supervisory control system used to telemeter operating data, provide device status/alarms, and remotely control equipment at a substation or generator site. The unit communicates with a master unit at the EPS operator's Control Center.

System Emergency: An imminent or occurring condition on the utility power delivery system, the ISO/RTO System, the system of a neighboring utility, or in the facility that is likely to impair system reliability, quality of service, or result in significant disruption of service or damage to any of the foregoing, or is likely to endanger life, property, or the environment.

Telemetry: The process of recording and transmitting the readings of an instrument. For example, collection of measurements or other data at remote or inaccessible points and their automatic transmission to receiving equipment for monitoring. In the case of DERs, applications include telemetry for protection device status, power flows, settings, and other facility or related utility equipment condition status.

Utility-Required Settings: A specific DER configuration regarding enter service, DER support of area EPS voltage, and DER response to abnormal conditions. Where appropriate, these settings may be common across large regions to simplify DER integration. The system operator has the right to establish tailored profiles to facilitate integration within the service territory or feeder segment. Utility-Required Settings may be DER project (site) specific.

2.2 Acronyms

AGIR	Authority Governing Interconnection Requirements
DA	Distribution Automation
DER	Distributed Energy Resource
EMI	Electromagnetic Interference
EPS	Electric Power System
ESS	Energy Storage System
MID	Microgrid Interconnect Device
PoC	Point of DER Connection
PCC	Point of Common Coupling
RPA	Reference Point of Applicability
TIIR	Technical Interconnection and Interoperability Requirements

3
TECHNICAL REVIEW PROCESS

EPRI Note: *This chapter is provided for use by the local power company when there is not an otherwise specified technical review process dictated by an external AGIR, such as the State, City, or Territory. It is a generic review process based on the FERC Small Generator Interconnection Procedure (SGIP), various State review processes, and EPRI's interconnection experience.*

3.1 Principles and Objectives of Technical Review

- DER interconnection and operation shall not compromise the safety of the public or utility personnel.
- DER interconnection shall not degrade service to any customers by causing interruptions or diminishing the quality of power.
- DER interconnection shall not compromise the security or reliability of utility electrical systems.
- DER shall be responsive to the utility's directions during emergency conditions or to requests to remove the DER from service when the utility is performing work in the area.

3.2 Process and Criteria for DER Interconnection

All DER interconnections will be evaluated for the following:

- Safety of the public and {UTILITY} personnel,
- Risk of degradation to services for customers due to interruptions or power quality events,
- Compromise of security or reliability of {UTILITY} electrical systems,
- Cost responsibility associated with customer-owned generation,
- Proper implementation and meeting terms of service,
- Relative DER size with respect to grid design and strength,
- DER performance relative to standards such as IEEE 1547-2018.

Developers and owners of approved DER interconnections are required to be responsive to the Utility's direction and instructions during emergency conditions or to remove the DER from service when {UTILITY} is performing line maintenance or other work on the circuit to which the DER is connected.

A customer shall not operate their Generating Facility in parallel with {UTILITY}'s EPS without the prior written consent and without full compliance with this procedure.

Qualified projects will undergo expedited or fast track technical screening and DER design evaluation, however a System Impact Study may be required prior to the interconnection of the Generating Facility which may include, but is not limited to the following:

- Site Visit,
- Distribution System Impact Study (if opting out or failing fast track review),
- Transmission System Impact Study (69kV and above or as needed).

Developers and owners of approved DER interconnections are required to be responsive to {UTILITY} direction and instructions during emergency conditions. This may require removing the DER from service when {UTILITY} is performing line maintenance or other work on the circuit to which the DER is connected.

3.3 Interconnection Application

Guidelines for processing DER interconnection applications and conducting related technical reviews are either specified in an applicable interconnection application process in the utility jurisdiction or otherwise herein. Details of the process depend on the size and complexity of the DER plant to be connected. A tiered evaluation approach includes the possibility of expedited approvals, interconnections requiring first-level screening, supplemental review, and/or detailed studies.

Built into the process are customer/developer options for pre-application studies, for supplemental review prior to commitment to more involved and expensive technical studies, and for decision meetings in cases where detailed study and/or system upgrades are indicated. A sample of the tiered approach is shown in Table 3-1.

Table 3-1
Tiers for Technical Review of DER Interconnections

Tier	Valid for Applications	Process description	Outcomes
Expedited review	{Less than 25kW}	Review to ensure customer is not on a restricted and/or network circuit	Approved or Referred for 1st level screening
First Level Screening	{25kW-250kW} -or- Applications that have not been approved through the expedited review	Checklist of screens serving as health indices which include aggregate DER.	Approved or Referred for 2nd level screening or study Any projects >250 kW will be referred to TVA Affected System Review.
Second Level Technical Review	{250kW or greater} -or- Applications that have not been approved through the pre-screen	Focused analysis including engineering judgement and more locational system-specific data.	Approved or Referred for detailed impact study. Any projects >250 kW will be referred to TVA Affected System Review.
Detailed Impact Study	Applications that have not been approved through a screen	Analysis involving tools and simulations that require feeder data, such as time-series production and load, impedances, regulation, and/or protection settings.	Approved or identified DER design modifications or distribution system modifications

			required to proceed.

EPRI Note: *The tiered screening process presented in Table 3-1 is designed to address higher volumes of DER interconnection applications with limited engineering resources and a reasonable level of evaluation. In the tiered technical review, the first level screening covers individual and aggregate DER impacts against conservative criteria limits. These screens are designed for application without the need for engineering judgement. Failing the first level, a second level review or "supplemental review" may include engineering judgement but avoids detailed modeling and simulation where possible. For larger and more complex DER applications, an impact study may be required.*

Guidelines for processing applications to interconnect DER in {UTILITY}'s service area, and the associated technical reviews are specified in this section. The details of required technical review depend on the size and complexity of the DER plant to be connected. A tiered evaluation approach, illustrated in Figure 3-1, provides the possibility of expedited approval, as well as of conducting progressively more involved interconnection reviews requiring first-level screening, supplemental review, and detailed studies.

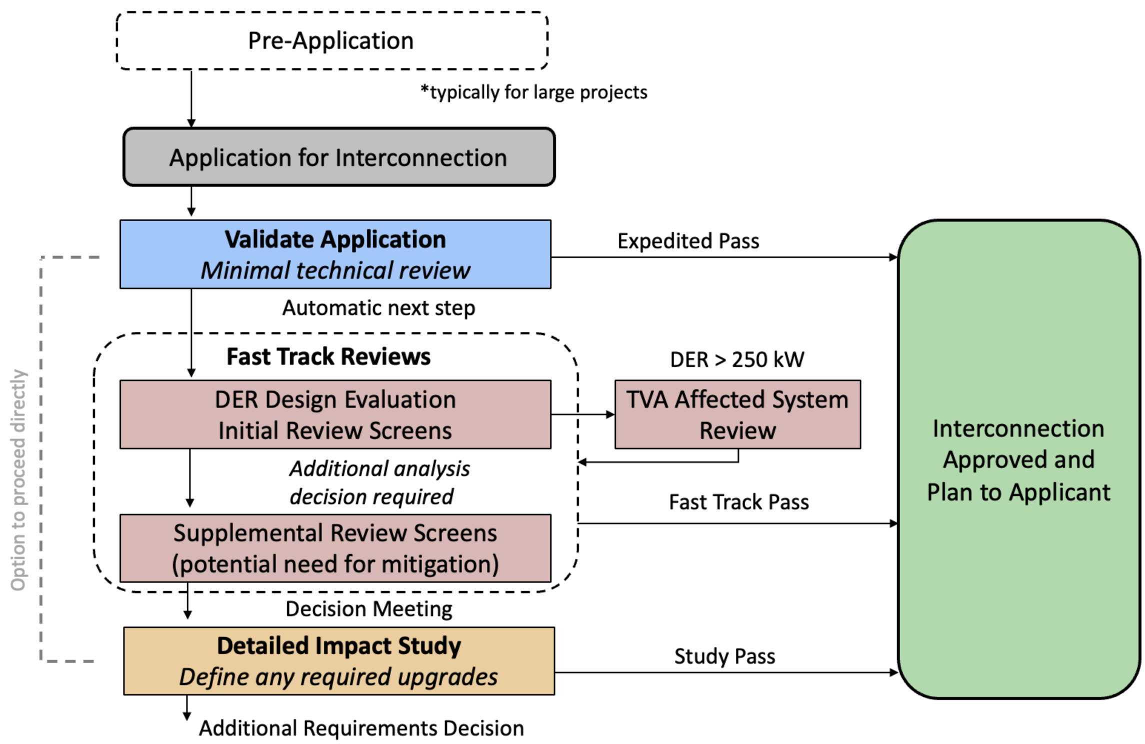


Figure 3-1
Overview of Tiered Interconnection Technical Review Process Flow

3.3.1 Technical Review Requirements

Technical requirements are defined for each level of review. They will depend on timely submission of DER plans and other project details needed to complete each review level. The primary technical areas to be covered include voltage regulation, protection, power quality and thermal limits. Other requirements include service requirement and metering, telemetry, and at higher power levels, bulk system stability and reactive power balance studies. In some cases, analytical tools and feeder data will be required to complete the review or study. Areas with high relative penetrations of DER are more likely to require additional review and detailed studies.

3.3.2 Pre-Application Option

An Interconnection Project may submit a formal written request form for a Pre-Application Report on a proposed project at a specific site. {UTILITY} will provide the PCC data to the Interconnection Customer within {15} business days of receipt of the completed request form and payment. The Pre-Application Report produced by {UTILITY} is non-binding, does not confer any rights, and the Interconnection Customer must still apply to interconnect. The written Pre-Application Report request must clearly identify the location of the proposed PCC by providing the following information:

1. Project contact information, including name, address, phone number, and email address.
2. Project location (street address with nearby cross streets and town). Interconnection Customer may choose to also provide an aerial map or GPS coordinates for increased accuracy.
3. Meter number, pole number, or other equivalent information (e.g., major intersection, GPS coordinates) identifying proposed PCC, if available.
4. DER type(s) (e.g., solar, wind, combined heat and power, storage, solar + storage, etc.).
5. Nameplate Rating (alternating current kW).
6. Single- or three-phase DER configuration.
7. Is a new service required? Yes or No.
8. If there is an existing service, include the customer account number, site minimum and maximum current or proposed electric loads in kW (if available), and specify how the load is expected to change.

EPRI Note: *Utility may opt not to offer a Pre-Application. In this case, omit this section. Utility may alternatively opt to require large or complex projects to complete pre-application steps prior to entering the interconnection queue.*

Using the information provided in the Pre-Application Report request form, {UTILITY} will identify the substation/area bus, bank, or circuit likely to serve the proposed PCC. If multiple PCCs are to be considered, the Interconnection Customer must request additional Pre-Application Reports.

A pre-application report provided by {UTILITY} will typically include the following information:

1. Total capacity (in megawatts, MW) of substation/area bus, bank or circuit based on normal or operating ratings likely to serve the proposed PCC.
2. Substation nominal distribution voltage and/or transmission nominal voltage if applicable.
3. Available capacity (in MW) of substation/area bus or bank and circuit likely to serve the proposed PCC (i.e., total capacity less the sum of existing aggregate generation capacity and noting the aggregate queued generation capacity). Identify whether the substation has a load tap changer.

4. Nominal distribution circuit voltage at the proposed PCC. Number and rating of protective devices and number and type (standard, bi-directional) of voltage regulating devices between the proposed PCC and the substation/area.
5. Approximate circuit distance between the proposed PCC and the substation. Number of phases available on the Area EPS medium voltage system at the proposed PCC. If a single-phase, distance from the three-phase circuit.
6. Relevant line section(s) actual or estimated peak load and minimum load data, including daytime minimum load and absolute minimum load, when available.

Based on the proposed PCC, {UTILITY} will identify existing or known constraints. Examples of constraints are voltage issues, short circuit interrupting capacity issues, power quality or stability issues on the circuit, capacity constraints, or secondary networks.

The Pre-Application Report needs only to include existing data. A request for a Pre-Application Report does not obligate {UTILITY} to conduct a study or other analysis of the proposed DER if data is not readily available. If {UTILITY} cannot complete all or some of a Pre-Application Report due to lack of available data, the report will include the data that is available.

EPRI Note: *"Available capacity" does not imply that an interconnection up to this level may be completed without impacts. There are many variables studied as part of the interconnection review process. The distribution system is dynamic and subject to change, and data provided in the Pre-Application Report may become outdated by the time of a completed Interconnection Application's submission. The utility shall, in good faith, include data in the Pre-Application Report that represents the best available information at the time of reporting.*

3.4 Technical Reviews

As described in Figure 3-1, the technical review process is intended to be tiered such that simpler projects can be expedited and where all qualifying projects are considered for a fast track review. In the case of larger and more complex interconnection application the proposer may elect to go directly to a more detailed level of review in order to save time.

3.4.1 Expedited Review Option

DER Applications meeting the following criteria may qualify for an expedited track, which limits the number of screens and the level of details required for interconnection:

- Designed and installed by preferred vendor,
- Residential or Commercial Behind-The-Meter system,
- Total DER Nameplate Capacity Less than or equal to {typically 25} kW,
- To be constructed in accordance with pre-approved design one-line template,
- Solar or Solar plus Storage, and
- Proposing interconnection in a region with available hosting capacity.

3.4.2 Fast Track Review Applicability

The Fast Track Review Process is available to a customer proposing to interconnect their DER with the Distribution System. Eligibility depends on the DER Export Capacity and does not exceed the size limits identified in Table 3-1. However, Fast Track eligibility is distinct from the Fast Track Process itself, and eligibility does not imply or indicate that a DER will pass all Initial Screening or Supplemental technical review.

Fast Track eligibility is determined based upon the DER type, the Export Capacity, interconnection voltage level, and the type of the utility line at the Point of Interconnection. Synchronous and induction machine DER may be eligible if certified according to UL 1741SB. Any DER connecting to lines greater than or equal to 35kV are not eligible for the Fast Track Process regardless of Export Capacity.

Certified inverter-based DER located within 2.5 electrical circuit miles of a substation and on a mainline (as defined in Table 3-2) are eligible for the Fast Track Process under the higher thresholds stipulated in Table 3-1. In addition, the Interconnection Customer's proposed DER must meet all relevant codes, standards, and certification requirements.

Table 3-2
Qualifications for a Fast Track Review

Line Voltage	DER Export Capacity Regardless of Location	DER Export Capacity on a Mainline[5] and ≤ 2.5 Electrical Circuit Miles from Substation[6]
< 5 kV	≤ {500 kW}	≤ {500 kW}
≤ 5 kV and < 15 kV	≤ {2 MW}	≤ {3 MW}
≤ 15 kV and < 30 kV	≤ {3 MW}	≤ {4 MW}
≤ 30 kV and ≤ 69 kV	≤ {4 MW}	≤ {5 MW}

EPRI Note: *The limits provided in Table 3-2 are typical to most fast track processes and related qualifications. Different size limits may be used at the discretion of the utility.*

3.4.3 Fast Track Initial Review

For any DER interconnection application qualifying for Fast Track, {UTILITY} will perform an initial screening within {15} business days of receiving a completed Interconnection Application. These screens are described below and cover both individual and aggregate DER in the vicinity of the interconnection. An application must pass all the screens to be eligible for approval for interconnection without further review. {UTILITY} will notify the Interconnection Customer of the results, including copies of the analysis and data underlying the determinations under these initial screens.

[5] For purposes of this table, a Mainline is the three-phase backbone of a circuit. It will typically constitute lines with wire sizes of 4/0 American wire gauge, 266 kcmil, 336.4 kcmil, 397.5 kcmil, 477 kcmil and 795 kcmil.

[6] An Interconnection Customer can determine this information about its proposed interconnection location in advance by requesting a pre-application report.

3.4.3.1 Initial Review Screens

1. **Service Territory**: The proposed DER's PCC must be on a portion of {UTILITY}'s service territory.

2. **Island Potential**: For interconnection of a proposed DER to a radial distribution circuit, the aggregated Export Capacity generation, including the proposed DER on the circuit shall not exceed 15% of the line section annual peak load as most recently measured at the substation. A line section is that portion of {UTILITY}'s distribution connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line. For solar, {UTILITY} may consider 100% of applicable loading (i.e. daytime minimum load for solar), if available, instead of 15% of line section peak load.

3. **Export Limiting**: For interconnection of a proposed DER approved for export limiting and that can introduce Inadvertent Export, where the Nameplate Rating minus the Export Capacity is greater than 250 kW, the following Inadvertent Export screen is required. With a power change equal to the Nameplate Rating minus the Export Capacity, the change in voltage at the point on the medium voltage (primary) level nearest the PCC does not exceed 3%. Voltage change will be estimated applying the following formula:

Formula	$\frac{(\boldsymbol{R_{Source}} \times \Delta\boldsymbol{P}) - (\boldsymbol{X_{Source}} \times \Delta\boldsymbol{Q})}{\boldsymbol{V^2}}$
Where: $\Delta\boldsymbol{P}$ = (DER apparent power Nameplate Rating – Export Capacity) × PF, $\Delta\boldsymbol{Q}$ = (DER apparent power Nameplate Rating – Export Capacity) × $\sqrt{(\boldsymbol{1 - PF^2})}$, R_{Source} is the grid resistance, X_{Source} is the grid reactance, V is the grid voltage and PF is the power factor	

   ***EPRI Note**: This screen has been added to traditional initial screens to address credit for export control capability and to prevent oversizing of DER relative to grid strength.*

4. **LV Network Limit**: For interconnection of a proposed DER to the load side of spot network protectors, the proposed DER must utilize an inverter-based equipment package and the proposed DER's export capacity, together with the aggregated Nameplate Rating of other inverter-based generation, shall not exceed the smaller of 5% of a spot network's maximum load or 50 kW.

5. **Aggregate Fault Current**: The fault current of the proposed DER, in aggregation with the fault current of other DER on the distribution circuit, shall not contribute more than 10% to the distribution circuit's maximum fault current at the point on the MV (primary) level nearest the proposed point of interconnection.

6. **Fault Interrupting Limits**: The fault current of the proposed DER, in aggregate with fault current of other DER on the distribution circuit, shall not cause any distribution protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or customer interconnection equipment on the system, to exceed 87.5 % of the short circuit interrupting capability.

7. **Shared Secondary Limits**: If the proposed DER is to be interconnected on single-phase shared transformer secondary, the aggregate generation capacity on the shared secondary,

including the proposed DER, shall not exceed 20 kW or 65% of the transformer nameplate rating.

8. **Low-Voltage Service Limits**: If the proposed DER is single-phase and is to be interconnected on a center tap neutral of a 240-volt service, its addition shall not create an imbalance between the two sides of the 240-volt service of more than 20% of the nameplate rating of the service transformer.
9. **Single-Phase DER Size Limits**: If the proposed DER is single-phase and is to be interconnected to a three-phase service, its Nameplate Rating shall not exceed 10% of the service transformer or 50kW, whichever is smaller.
10. **Regulation Compatibility**: If the DER's PCC is behind a line voltage regulator[7], the DER's Nameplate Rating shall be less than 500 kW.
11. **Transmission "Affected System":** If the DER nameplate capacity is greater than 250 kW, project will be referred to TVA for Affected System screening. All other screens and processes will proceed per {Utility} process however, permission to construct will not be granted without approval from TVA affected system process.

EPRI Note: *Initial screening provides checks for some of the most common issues when adding DER to an existing feeder or service. It does not address feeder voltage regulation beyond individual DER size limits. (Feeder voltage regulation may also be impacted by the distribution of aggregate DER and this evaluation requires a feeder model and a time series evaluation [static load flow]). It is a good idea to run a load flow at the supplemental review level when considering voltage quality. It is further recommended that the initial screening not attempt to address system grounding compatibility, or effective grounding, of feeder sections. Experience indicates that grounding decisions require engineering judgement and are best treated at the supplemental review level.*

If the proposed interconnection passes all the initial screens and any DER Design Evaluation, then {UTILITY} will provide the Interconnection Customer with an executed Interconnection Agreement within {5} business days after the determination.

If the proposed interconnection passes the screening and requires construction of any facilities, {UTILITY} will notify the Interconnection Customer of such requirement when it provides the Initial Review results. This normally includes related analysis and data underlying the determination. If the construction requirement is clear, then {UTILITY} may provide a good faith cost estimate; if it is not clear then the requirement for a supplemental review or a facilities study will be indicated.

If the proposed interconnection fails initial screening and requires additional review, then a decision to proceed with the additional review will be required in writing from the interconnection customer.

[7] This screen does not include substation voltage regulators.

Within {5} business days, the Interconnection Customer shall inform {UTILITY} if they intend to proceed with either required construction or further technical review, or to withdraw the application.

3.4.4 Customer Options Meeting

If {UTILITY} is informed of a desire to proceed, then {UTILITY} and Interconnection Customer shall within {10} business days schedule a customer options meeting to review 1) possible facility modifications, 2) screen analysis, and/or 3) related results to determine what further steps are needed to permit the DER to be connected safely and reliably. At the time of notification of {UTILITY}'s determination, or at the customer options meeting, {UTILITY} shall:

- Offer to perform a supplemental review in accordance with section 3.4.5 and provide a non-binding good faith estimate of the costs of such review; or
- Obtain the Interconnection Customer's agreement to continue evaluating the Interconnection Application via the Study Process and provide a non-binding good faith estimate of the costs of such review.

3.4.5 Supplemental Review

To accept the offer of a supplemental review, the Interconnection Customer shall agree in writing and submit a deposit for the estimated costs of the supplemental review based on {UTILITY}'s good faith estimate of the costs, both within {15} business days of the offer.

The Interconnection Customer shall be responsible for {UTILITY}'s actual costs for conducting the supplemental review. The Interconnection Customer shall pay any review costs that exceed the deposit within twenty {20} business days of receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced costs, {UTILITY} will return such excess within {20} business days of the invoice without interest. Within {30} business days following receipt of the deposit for a supplemental review the {UTILITY} shall: 1) perform a supplemental review using the screens set forth below, 2) notify in writing the Interconnection Customer of the results, and 3) include with the notification copies of the analysis and data underlying {UTILITY}'s determinations under the screens. {UTILITY} shall notify the Interconnection Customer following failure of any supplemental review tests.

EPRI Note: *The objective of supplemental review is to add engineering judgement when first level review, initial screening, fails. It may be possible to avoid further study, saving time and effort. Supplemental review tests cover broad topics, ranging from concern for unintended islands to power quality and reliability issues. Specific criteria may be difficult to predetermine. Also, relative to this document, requirements described in chapter 11 on feeder compatibility may be applicable.*

3.4.5.1 Supplemental Review Tests

1. **Minimum Load Test with respect to Unintended Islanding:** Where 12 months of line section minimum load data (including onsite load, but not station service load served by the proposed DER) are available, can be calculated or estimated from existing data, or determined from a power flow model, the aggregate DER capacity on the line section is less than 100% of the minimum load for all line sections bounded by automatic sectionalizing devices upstream of the proposed DER.

- The type of generation used by the proposed DER will be considered when calculating, estimating, or determining circuit or line section minimum load relevant for this application. Solar photovoltaic (PV) generation systems with no battery storage use daytime minimum load (i.e., 10 a.m. to 4 p.m. for fixed panel systems and 8 a.m. to 6 p.m. for PV systems utilizing tracking systems), while all other generation uses absolute minimum load.
- When this screen is being applied to a DER that serves some station service load, only the net injection into {UTILITY}'s electric system will be considered as part of the aggregate generation. For the purposes of this screen, DER capacity known to be already reflected in the minimum load data will not be considered as part of the aggregate generation. For example, if minimum load is 500 kW and two years after DER are installed, it is 400 kW, 100 kW of DER should not be double-counted against the new minimum load.

EPRI Note: *When DER are interconnected to the same feeder as the proposed DER, utilities should account for existing Direct Transfer Trip protected DER in their assessment of minimum load and island risks.*

2. **Voltage and Power Quality Test**: In aggregate with existing generation on the line section: (1) the voltage regulation on the line section can be maintained in compliance with relevant requirements under all system conditions; (2) the voltage fluctuation is within acceptable limits as defined by IEEE Standard 1453, or utility practice similar to IEEE Standard 1453; and (3) the harmonic levels meet IEEE Standard 519 limits.

   EPRI Note: *It is best to run a load-flow analysis to determine if there may be a voltage regulation issue. Depending on available feeder data and tools, some utilities conduct a voltage regulation check at the supplemental review level. Also, the risk of rapid voltage change can be evaluated based on the stiffness ratio at the PCC. (It is recommended that the stiffness ratio be greater than 10 times the short circuit MVA relative to DER MVA.) Other power quality impacts, such as harmonic distortion and flicker, may be more difficult to predict and are otherwise covered by DER certification requirements. If unexpected issues occur after installation, power quality monitoring is expected to identify responsibility.*

3. **Safety and Reliability Test**: The location of the proposed DER and the aggregate generation capacity on the line section do not create impacts to safety or reliability that cannot be adequately addressed without application of the Study Process. {UTILITY} shall give due consideration to the following and other factors in determining potential impacts to safety and reliability in applying this screen.

   - Whether the line section has significant minimum loading levels dominated by a small number of customers (e.g., several large commercial customers).
   - Whether the loading along the line section is uniform or even.
   - Whether the proposed DER is near the substation (i.e., less than 2.5 electrical circuit miles), and whether the line section from the substation to the PCC is a main line rated for normal and emergency ampacity.

- Whether the proposed DER incorporates a time delay function to prevent reconnection of the generator to the system until system voltage and frequency are within normal limits for a prescribed time.

- Whether operational flexibility is reduced by the proposed DER, such that transfer of the line section(s) of the DER to a neighboring distribution circuit/substation may trigger overloads or voltage issues.

- Whether the proposed DER employs equipment or systems certified by a recognized standards organization to address technical issues such as, but not limited to, islanding, reverse power flow, or voltage quality.

4. ***Grounding Compatibility Test***: Determine if supplemental grounding is required to maintain effective grounding based on the DER interconnection transformer winding configuration (see chapter 4, grounding). If supplemental grounding is required, then provide the option to modify the DER system to include the necessary grounding equipment without proceeding to full study and before an interconnection agreement is provided.

   EPRI Note: *The grounding compatibility test can be done using EPRI tools such as the Inverter-Based Supplemental Grounding Tool. Additionally, a detailed hosting capacity analysis using tools, such as EPRI DRIVE, which incorporates evaluation of temporary overvoltage risk for inverters, may be used in lieu of the test.*

5. ***Reverse Power and Ground Fault Overvoltage:*** In case of three-phase, certified inverter-based DER failing the minimum load test and passing other supplemental tests, consider these additional criteria:

   - Is the feeder and/or the substation capable of anticipated reverse power flow (line regulator controls for two-way power, feeder and substation capacity to receive import, etc.)?
   - Does the inverter-based DER plant have a utility-controlled recloser and relay with zero-sequence current detection function (“3I0” in combination with a grounding bank) or a zero-sequence overvoltage function (3V0) set to disconnect the plant?

   EPRI Note: *This additional test may allow DER to exceed minimum load without study.*

If the proposed interconnection passes the relevant supplemental screens, {UTILITY} shall provide the Interconnection Customer with an executable Interconnection Agreement within {5} business days.

If the proposed interconnection requires construction of any facilities, {UTILITY} shall notify the Interconnection Customer of such requirement when it provides the supplemental review results and either:

- Provide a good faith cost estimate, or

- Require facilities study, wherein costs are determined.

If the application fails supplemental review, {UTILITY} shall provide the Interconnection Customer with the option of proceeding to the Detailed Study stage. If the Interconnection Customer wishes to proceed, it shall notify {UTILITY} within {15} business days to retain its queue position.

3.4.6 Detailed Study

To accept the offer of a detailed study, the Interconnection Customer shall agree in writing and submit a deposit for the estimated costs of required studies based on {UTILITY}'s good faith estimate of the costs within {15} business days of the offer.

Any necessary studies will be determined by {UTILITY} and may be informed by either initial screening or supplemental technical review. Typical areas included in technical review studies are described in this section and summarized in EPRI Note*: Additional components of the Detailed Study Track can be described as needed (e.g., Feasibility Study, Facilities Study, etc.) and in EPRI 3002021972.*

Table 3-3
Comprehensive System Impact Study. These studies are conducted based upon a review of the specific DER, location, and utility engineering practices. The estimated cost of any study must be paid by the Interconnection Customer. Upon completion of the study actual costs will determine additional cost or refund.

3.4.6.1 System Impact Study

As listed in Table 3-3, a system impact study shall identify and detail the electric system impacts that would result if the proposed DER were interconnected without project modifications or electric system modifications, focusing on the adverse system impacts identified in a feasibility study, or to study potential impacts, including but not limited to those identified in a scoping meeting. A system impact study shall evaluate the impact of the proposed interconnection on the reliability of the electric system.

The system impact study must consider the proposed DER's design and operating characteristics, including but not limited to the applicant's proposed Operating Profile where verifiable, and study the project according to how the project is proposed to be operated. If the DER limits export by an approved method the system impact study will use Export Capacity instead of the Nameplate Rating, except when assessing fault current contribution. To assess fault current contribution, the system impact study must use the rated fault current; for example, the Customer may provide manufacturer test data (pursuant the fault current test described in IEEE 1547.1-2020 clause 5.18) showing that the fault current is independent of the Nameplate Rating.

***EPRI Note:** Additional components of the Detailed Study Track can be described as needed (e.g., Feasibility Study, Facilities Study, etc.) and in EPRI 3002021972.*

Table 3-3
Comprehensive System Impact Study

Study Component	Criteria Evaluated
Load Flow	Steady State voltage, voltage unbalance, regulator tap movements
Power Quality	Voltage Fluctuations (e.g., TOV, flicker or RVC, inadvertent export events)
Thermal	Component current and energy limits, cycle times
Protection	Short circuit current, coordination, interrupt rating, breaker reach

System Grounding	Risk of Islanding, TOV
Stability (EMT)	Dynamic response and transient behavior

3.4.7 Expected Technical Review Outcomes and Approvals

The expected outcome when applications are approved via technical review is a formal written notice provided to the Customer with an 'Approval to Install' or 'Permission to Construct' letter. For any system subject to detailed study process, {UTILITY} coordination with TVA as an affected system will be required. 'Approval to Install' or 'Permission to Construct' will depend on the result of TVA Affected System process.

In cases where DER design and operation are identified as potentially impacting grid operation, conditional approval may be granted. The expected outcomes in case of conditionally approved applications are to provide the applicant with written notification and the specific conditions and requirements for interconnection—including the estimated cost, when applicable. Three different conditional approvals are typically encountered:

- Conditional with agreed to changes in the proposed DER system design.
- Conditional with changes to DER operation, such as limited operating modes, and including utility control and/or curtailment of the DER under certain contingency circumstances.
- Conditional, requiring utility system enhancement to resolve an issue identified in the technical review and paid for by the applicant.

Upon the completion of Customer and/or {UTILITY} work, the applicant must have received a written 'authorization or permission to operate' prior to energization of the DER. {UTILITY} reserves the right to inspect any DER at the time of installation or any time thereafter.

4

GENERAL TECHNICAL REQUIREMENTS

The DER interconnection shall comply with IEEE 1547-2018 and IEEE 1547.1-2020. Inverters and synchronous or induction machines, whenever possible, shall be UL 1741 SB certified and installed or commissioned with the IEEE 1547-2018-specified performance capabilities.

EPRI Note: *The expectation is that non-certified systems will need to be scrutinized to demonstrate how they meet each capability described herein and in IEEE 1547-2018 by reference. In addition, the Customer is responsible for complying with other codes such as the National Electrical Code, Local Safety Codes, NERC rules (applicable for independent system operators), and any applicable regulations imposed by the local AHJ. Compliance includes installing, setting, and maintaining all protective devices necessary for safe area EPS integration and for protecting the Customer's facilities.*

4.1 Applicable Voltages

DER proposing interconnection within {UTILITY} distribution system will be:

- **Medium Voltage Interconnections –** Primary connected at applicable distribution primary voltages as determined by the nominal operating voltage at the PCC.
- **Low Voltage Interconnections –** Single-phase or three-phase line-side or load-side connected at Single-phase 120V/240V | Three-Phase LG 277V, LL 480V and subject to the limitations of the service transformer at the PCC.

4.2 Transformer and Grounding Compatibility

4.2.1 Service Transformer Connections

Low voltage interconnections are normally connected via an existing load service transformer. Medium voltage interconnected and large facilities relative to the local load center may require either an upgrade of the service transformer or the addition of a DER facility service transformer.

Three-phase service may be required for all DER rated {50} kW or larger.

4.2.2 Transformer Configuration Requirement

The following transformer winding configuration requirements shall apply. The Utility side is determined by Area EPS configuration. The DER side will be dictated by the plant design.

Table 4-1
Transformer Winding Configuration Requirements

Utility System	Utility Winding	DER Winding	Comments
13.2kV (4 wire)	Wye - Grd	Wye - Grd	(usually preferred)
	Wye - Grd	Wye	(usually preferred)

	Wye – Grd	Delta	May require reactor
34.5kV (3 wire uni-grounded) and 4.8kV (3 wire ungrounded)	Delta	Wye-Grd, Delta or Wye	

EPRI Note: *Modify Table 4-1 to indicate preferred configurations, utility side connections, and identify where combinations may trigger additional review.*

The allowable transformer winding configurations can be complicated and are based on the Area EPS system design, effective grounding considerations, and the requirements of the proposed DER system. Typically, the Area EPS will select the MV winding based on the Area EPS design (i.e., often 4-wire connections require Yg, and 3-wire require ungrounded). The secondary winding will be tied to the requirements of the DER system (i.e., often rotating machines, central inverters, and energy storage systems will require ungrounded, and string inverters will require grounded secondaries). For ungrounded secondaries, the decision between an ungrounded Y and Δ will be determined based on DER requirements and utility effective grounding practices.

4.2.3 Effective Grounding

Requirements for effective grounding are specified in IEEE 1547-2018 clause 4.12 – Integration with Area EPS Grounding.

The DER interconnection (inclusive of DER assets and interconnecting transformer) must be compatible with the feeder grounding practice at the PCC. With some exceptions, installations should meet the requirements for "effectively grounded," as described in IEEE/ANSI C62.92.2 for synchronous machines, and C62.92.6 for inverters. In addition, where applicable, grounding requirements identified in the National Electrical Code and local codes shall be met.

4.3 Additional General Technical Requirements of DER

In alignment with IEEE 1547, the following performance requirements should be satisfied by DER proposing interconnection and parallel operation. Their associated clauses are provided in the Table 4-2.

Table 4-2
DER Technical Performance Requirements with Associated IEEE 1547 Clauses

Requirement	IEEE 1547-2018 Clause
Measurement Accuracy	*Clause 4.4 includes steady state and transient measurement windows, accuracy, and range across parameters governing DER capability.*
Cease to Energize	*Clause 4.5 describes cease to energize such that DER may maintain auxiliary self-power to continue to assess grid conditions and perform service re-entry routine.*

Control Capability	*DER shall be capable, per clause 4.6, of receiving an external signal that disables service re-entry, to limit active power, or by changing active modes or parameters.*
Prioritization of DER Response	*Prioritization in this context is not based on grid need or operational discretion. 1547 lays out the hierarchy of functions such as trip, frequency droop, ride-through, and power mode. Certified DER must follow this prioritization as part of their active response to system conditions.*

4.4 Reference points of applicability (RPA)

The characteristics of the Local EPS and DER shall determine an RPA. The RPA for all performance requirements shall be the PCC except as stated in IEEE 1547-2018 clause 4.2. The RPA may be an alternate location for situations which include the power output rating of the DER, power output rating of the DER relative to other load levels on the Local EPS, power export capability of the Local EPS, and zero sequence continuity between the PCC and PoC.

EPRI Note: *The location of the RPA can get complicated as several factors determine the location. IEEE 1547.2 is a good reference for identifying the RPA location. A common utilization of the RPA is for large front-of-the-meter installations with a wye/delta transformer (lacking zero sequency continuity), which drives voltage sensing on the MV side.*

4.5 Disconnect Switch

A manual disconnect switch, of the visible load break type, shall be required to provide a separation point between DER and {UTILITY}'s electrical system. This switch will be furnished and installed by the customer, in a visible location that is always accessible to {UTILITY} personnel. The switch will be installed as close to the meter as practical and be capable of being locked in the open position with a {UTILITY} padlock. The switch shall meet all applicable local and national electrical codes.

The disconnect switch shall be permanently labeled, clearly stating "DER Disconnect Switch." If the disconnect switch is mounted out of sight of the meter, additional permanent signage must be posted at the revenue meter clearly stating the location of the {UTILITY}-accessible disconnect switch and a contact number that can be called 24 hours a day.

4.6 Inadvertent Energization of Area EPS

DER shall not inadvertently energize the Area EPS per IEEE 1547-2018 clause 4.9.

4.7 Enter Service

The voltage and frequency settings to be used shall be the default values for voltage and frequency ranges as displayed in Table 4 in IEEE 1547-2018 clause 4.10.2 – Enter Service Criteria. The default values for delays and ramp rate shall be used as identified in IEEE 1547-2018 clause 4.10.3 – Performance during entering service.

EPRI Note: *Min and max ranges and defaults for utility-specific settings are given in the far-right column in Table 4-3. Once Enter Service Criteria has been determined, fill in the blank* *columns in the table below and delete the reference Table 4-3. If settings outside of default are used, modify clause 4.7.*

Table 4-3
IEEE 1547-2018 Section 4.10 Enter Service Settings

ENTER SERVICE CRITERIA *EPRI Note: Fill out the Table 4-2 and remove this reference table for TIIR implementation.*		EPRI Common File Format	UNITS	IEEE Std 1547-2018 Ranges		
				Default	Min	Max
Permit Service		ES_PERMIT_SERVICE-SS	Mode	Enabled	-	-
Enter Service Voltage	ES Voltage Low Setting	ES_V_LOW-SS	V p.u.	0.917	0.88	0.95
	ES Voltage High Setting	ES_V_HIGH-SS	V p.u.	1.05	1.05	1.06
Enter Service Frequency	ES Frequency Low Setting	ES_F_LOW-SS	Hz	59.5	59.0	59.9
	ES Frequency High Setting	ES_F_HIGH-SS	Hz	60.1	60.1	61.0
Soft-Start Ramp	ES Randomized Delay	ES_RANDOMIZED_DELAY-SS	s	300	1	1000
	ES Delay Setting	ES_DELAY-SS	s	300	0	600
	ES Ramp Rate Setting	ES_RAMP_RATE-SS	s	300	1	1000

ENTER SERVICE CRITERIA		**EPRI Common File Format**	**UNITS**	**Utility-Required Settings**
Permit Service		ES_PERMIT_SERVICE-SS	Mode	{Enabled}
Enter Service Voltage	ES Voltage Low Setting	ES_V_LOW-SS	V p.u.	{0.917}
	ES Voltage High Setting	ES_V_HIGH-SS	V p.u.	{1.05}
Enter Service Frequency	ES Frequency Low Setting	ES_F_LOW-SS	Hz	{59.5}
	ES Frequency High Setting	ES_F_HIGH-SS	Hz	{60.1}
Soft-Start Ramp	ES Randomized Delay	ES_RANDOMIZED_DELAY-SS	s	{300}
	ES Delay Setting	ES_DELAY-SS	s	{300}
	ES Ramp Rate Setting	ES_RAMP_RATE-SS	s	{300}

4.7.1 Synchronization

Requirements for synchronization are specified in IEEE 1547-2018 clause 4.10.4 – Synchronization. DER shall not exceed limits to frequency, voltage, or phase angle while paralleling with the area EPS.

4.8 DER Interconnect integrity

DER and any plant controls shall be designed such that their operation is not compromised by typical conditions, including fault conditions presented at DER terminals by the area EPS. This includes electromagnetic compatibility, surge, and high voltage withstand. Requirements for DER Interconnection Integrity are specified in IEEE 1547-2018 clause 4.11 – Interconnect Integrity.

Basic Insulation Levels (BIL)

The BIL rating of any new transformer, circuit breakers, reclosers, and any other electrical equipment connected to the utility power system must coordinate with the requirements of the utility system at the PCC. All customer equipment should be designed to the BIL rating of the utility line to which it is interconnected.

5

DER SUPPORT OF GRID VOLTAGE

5.1 Reactive Power Capability

All DER installations will be required to have reactive power support capability. Requirements for reactive power capability are specified in IEEE 1547-2018, clause 5.2 – Reactive Power Capability of the DER. Category A for rotating machines and Category B for inverters shall be used to define capabilities for DER Support of Grid Voltage per IEEE 1547-2018.

Table 5-1
Assignment of IEEE 1547-2018 normal performance categories to various types of DERs

Power Conversion	Prime Mover (Energy Source)	Reactive Power Support
Inverter	Solar PV, Battery Energy Storage, Wind, Fuel Cell	Category B
Synchronous and Induction	Bio-/Landfill Gas, Fossil Fuel, Hydro, Combined Heat & Power	Category A

EPRI Note: *Performance Category B allows the DER to absorb up to 44% reactive power. This can be beneficial for systems with high penetration of DER which can help to alleviate concern of high steady state voltages. Category B also allows for Volt-Watt and Watt-VAR modes. These modes are DER capability requirements which the utility may optionally enable. (Tables 5-2 thru 5-6 represent utility settings configurations). A DER's ability to provide reactive power enables it to support and respond to changes in grid voltage beyond ANSI limits.*

Refer to Appendix G for a sample of full DER settings specifications. Note that in most cases two modes cannot be enabled simultaneously.

5.2 Reactive Power Control

Requirements for reactive power control mode defaults are specified in IEEE 1547-2018 clause 5.3 – Voltage and Reactive Power Control. Exceptions are indicated in Table 5-2.

EPRI Note*: The colored tables presented below provide ranges and default settings. When publishing requirements, fill out Utility Required Settings column of black and white table and remove reference table.*

Table 5-2
Constant Power Factor Settings

{CHOOSE: Default values shown; may choose utility-specific settings between min and max}

CONSTANT POWER FACTOR MODE (Specified Power Factor)	EPRI Common File Format	UNITS	IEEE Std 1547-2018 Category B		
			Default	Min	Max
Constant Power Factor Mode	CONST_PF_MODE_ENABLE-SS	Mode	Enabled	Enabled	Disabled
Constant Power Factor Excitation	CONST_PF_EXCITATION-SS	Mode	INJ	ABS	INJ
Constant Power Factor setting	CONST_PF-SS	PF	-	0.90	1.00

CONSTANT POWER FACTOR MODE (Specified Power Factor)	EPRI Common File Format	UNITS	Utility-Required Setting
Constant Power Factor Mode	CONST_PF_MODE_ENABLE-SS	Mode	{Enabled}
Constant Power Factor Excitation	CONST_PF_EXCITATION-SS	Mode	{INJ}
Constant Power Factor setting	CONST_PF-SS	PF	{1.00}

EPRI Note: *Constant power factor mode allows DERs to operate at a fixed power factor (PF), adjustable ratio of active to reactive power between 0.90 and 1.00 regardless of voltage or active power generation. The common default DER deployment is constant power factor at unity (1.00), resulting in strictly real power production.*

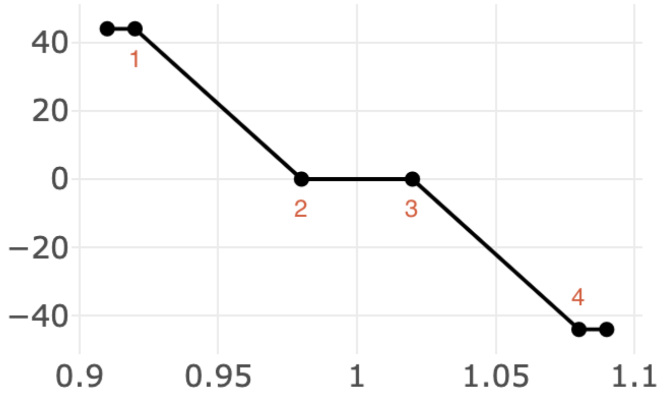
Table 5-3
Volt - Reactive Power Control (Volt-VAR) Settings

VOLT-REACTIVE POWER (Volt-Var Mode, Q(V), Voltage-Droop)		EPRI Common File Format	UNITS	IEEE Std 1547-2018 Category B		
				Default	Min	Max
Voltage-Reactive Power Mode Enable		QV_MODE_ENABLE-SS	Mode	Disabled	Enabled	Disabled
Near Nominal	Vref	QV_VREF-SS	V p.u.	1.00	0.95	1.05
	Autonomous Vref Adjustment Enable	QV_VREF_AUTO_MODE-SS	Mode	Enabled	Enabled	Disabled
	Vref adjustment time Constant	QV_VREF_OLRT-SS	s	-	300	5000

Point 2	V/Q Curve Point V2 Setting	QV_CURVE_V2-SS	V p.u.	0.980	0.920	1.05
	V/Q Curve Point Q2 Setting	QV_CURVE_Q2-SS	Q p.u.	0.00	-1.00	1.00
Point 3	V/Q Curve Point V3 Setting	QV_CURVE_V3-SS	V p.u.	1.020	0.95	1.08
	V/Q Curve Point Q3 Setting	QV_CURVE_Q3-SS	Q p.u.	0.00	-1.00	1.00
Point 1	V/Q Curve Point V1 Setting	QV_CURVE_V1-SS	V p.u.	0.92	0.77	1.03
	V/Q Curve Point Q1 Setting	QV_CURVE_Q1-SS	Q p.u.	0.44	0.00	1.00
Point 4	V/Q Curve Point V4 Setting	QV_CURVE_V4-SS	V p.u.	1.08	0.97	1.23
	V/Q Curve Point Q4 Setting	QV_CURVE_Q4-SS	Q p.u.	-0.44	-1.00	0.00
QV Open Loop Response Time Setting		QV_OLRT-SS	s	5	1	90

VOLT-REACTIVE POWER (Volt-VAR Mode, Q(V), Voltage-Droop)		**EPRI Common File Format**	**UNITS**	**Utility-Required Setting**
Voltage-Reactive Power Mode Enable		QV_MODE_ENABLE-SS	Mode	{Disabled}
Near Nominal	Vref	QV_VREF-SS	V p.u.	{1.00}
	Autonomous Vref Adjustment Enable	QV_VREF_AUTO_MODE-SS	Mode	{Enabled}
	Vref adjustment time Constant	QV_VREF_OLRT-SS	s	{CHOOSE}
Point 2	V/Q Curve Point V2 Setting	QV_CURVE_V2-SS	V p.u.	{0.980}
	V/Q Curve Point Q2 Setting	QV_CURVE_Q2-SS	Q p.u.	{0.00}
Point 3	V/Q Curve Point V3 Setting	QV_CURVE_V3-SS	V p.u.	{1.020}
	V/Q Curve Point Q3 Setting	QV_CURVE_Q3-SS	Q p.u.	{0.00}
Point 1	V/Q Curve Point V1 Setting	QV_CURVE_V1-SS	V p.u.	{0.92}
	V/Q Curve Point Q1 Setting	QV_CURVE_Q1-SS	Q p.u.	{0.44}
Point 4	V/Q Curve Point V4 Setting	QV_CURVE_V4-SS	V p.u.	{1.08}
	V/Q Curve Point Q4 Setting	QV_CURVE_Q4-SS	Q p.u.	{-0.44}
QV Open Loop Response Time Setting		QV_OLRT-SS	s	{5}

Figure 5-1
Category B Default Volt-VAR Curve



EPRI Note: *Volt-VAR is a commonly used function that can help to mitigate high voltages on the distribution circuit. Attention to the proximity and setpoints of regulators/capacitors to the DER must be accounted for. There is a challenge in determining a standard for a utility as it is site specific. The distance to the substation and the X/R ratio at the PCC has a strong influence on the benefit of non-unity power factor. Providing VARs can have unintended consequences during a utility's voltage reduction schemes. Volt-VAR can be considered as a "no-harm" alternative, even close to the substation where it would not be expected to be enabled. Points 1-4 in Table 5-3 are visually represented in* ***Error! Reference source not found.****. Voltage per unit is represented on the x axis, and Q (VARs) on the y axis.*

Table 5-4
Active Power - Reactive Power Control (Watt-VAR) Settings

ACTIVE POWER-REACTIVE POWER (Watt-Var Mode, Q(P))		EPRI Common File Format	UNITS	IEEE Std 1547-2018 Category B		
				Default	Min	Max
Active Power Reactive Power Mode Enable		QP_MODE_ENABLE-SS	Mode	Disabled	Enabled	Disabled
Active Power, Generation	P-Q curve P3 Setting	QP_CURVE_P3_GEN-SS	P p.u.	1.00	0.60	1.00
	P-Q curve P2P-Q Setting	QP_CURVE_P2_GEN-SS	P p.u.	0.50	0.40	0.80
	P-Q curve P1 Setting	QP_CURVE_P1_GEN-SS	P p.u.	0.20	0.00	0.70
Active Power, Absorption	P-Q curve P1 Setting	QP_CURVE_P1_LOAD-SS	P p.u.	-0.20	-0.70	0.00
	P-Q curve P2 Setting	QP_CURVE_P2_LOAD-SS	P p.u.	-0.50	-0.80	-0.40

	P-Q curve P3 Setting	QP_CURVE_P3_LOAD-SS	P p.u.	-1.00	-1.00	-0.50
Reactive Power, Generation	P-Q curve Q3 Setting	QP_CURVE_Q3_GEN-SS	S p.u.	-0.44	-1.00	1.00
	P-Q curve Q2 Setting	QP_CURVE_Q2_GEN-SS	Q p.u.	0.00	-1.00	1.00
	P-Q curve Q1 Setting	QP_CURVE_Q1_GEN-SS	Q p.u.	0.00	-1.00	1.00
Reactive Power, Absorption	P-Q curve Q1 Setting	QP_CURVE_Q1_LOAD-SS	Q p.u.	0.00	-1.00	1.00
	P-Q curve Q2 Setting	QP_CURVE_Q2_LOAD-SS	Q p.u.	0.00	-1.00	1.00
	P-Q curve Q3 Setting	QP_CURVE_Q3_LOAD-SS	S p.u.	0.44	-1.00	1.00

ACTIVE POWER-REACTIVE POWER (Watt-Var Mode, Q(P))		**EPRI Common File Format**	**UNITS**	**Utility-Required Setting**
Active Power Reactive Power Mode Enable		QP_MODE_ENABLE-SS	Mode	{Disabled}
Active Power, Generation	P-Q curve P3 Setting	QP_CURVE_P3_GEN-SS	P p.u.	{1.00}
	P-Q curve P2P-Q Setting	QP_CURVE_P2_GEN-SS	P p.u.	{0.50}
	P-Q curve P1 Setting	QP_CURVE_P1_GEN-SS	P p.u.	{0.20}
Active Power, Absorption	P-Q curve P1 Setting	QP_CURVE_P1_LOAD-SS	P p.u.	{-0.20}
	P-Q curve P2 Setting	QP_CURVE_P2_LOAD-SS	P p.u.	{-0.50}
	P-Q curve P3 Setting	QP_CURVE_P3_LOAD-SS	P p.u.	{-1.00}
Reactive Power, Generation	P-Q curve Q3 Setting	QP_CURVE_Q3_GEN-SS	S p.u.	{-0.44}
	P-Q curve Q2 Setting	QP_CURVE_Q2_GEN-SS	Q p.u.	{0.00}
	P-Q curve Q1 Setting	QP_CURVE_Q1_GEN-SS	Q p.u.	{0.00}
	P-Q curve Q1 Setting	QP_CURVE_Q1_LOAD-SS	Q p.u.	{0.00}

Reactive Power, Absorption	P-Q curve Q2 Setting	QP_CURVE_Q2_LOAD-SS	Q p.u.	{0.00}
	P-Q curve Q3 Setting	QP_CURVE_Q3_LOAD-SS	S p.u.	{0.44}

Table 5-5
Constant Reactive Power Control Settings

CONSTANT POWER FACTOR MODE (Specified Power Factor) ***EPRI Note**: Fill out Table 5-5 and remove this reference table for TIIR implementation*	EPRI Common File Format	UNITS	IEEE Std 1547-2018 Category B		
			Default	Min	Max
Constant Reactive Power Mode Enable	CONST_Q_MODE_ENABLE-SS	Mode	Disabled	Enabled	Disabled
Constant Reactive power setting	CONST_Q-SS	% S	0	-44.00	44.00

CONSTANT REACTIVE POWER MODE (Specified Power Factor)	**EPRI Common File Format**	**UNITS**	**Utility-Required Setting**
Constant Reactive Power Mode Enable	CONST_Q_MODE_ENABLE-SS	Mode	{Disabled}
Constant Reactive power setting	CONST_Q-SS	% S	{0}

5.3 Active Power Control

Requirements for active power control mode are specified in IEEE 1547-2018 clause 5.4 – Voltage and Reactive Power Control.

Category B DER shall have voltage-active power mode {Disabled}. The settings for the voltage-active power mode shall be the default values in Table 10 of IEEE 1547-2018 – “Voltage-active power settings for Category A and Category B DER.”

Table 5-6
Active Power Control (Volt-Watt) Settings

VOLT-ACTIVE POWER MODE (Volt-Watt Mode, P(V)) ***EPRI Note**: Fill out Table 5-6 and remove this reference table for TIIR implementation*	EPRI Common File Format	UNITS	IEEE Std 1547-2018 Category B		
			Default	Min	Max
Voltage-Active Power Mode Enable	PV_MODE_ENABLE-SS	Mode	Disabled	Enabled	Disabled

Point 1	PV Curve Point V1 Setting	PV_CURVE_V1-SS	V p.u.	1.06	1.05	1.09
	PV Curve Point P1 Setting	PV_CURVE_P1-SS	P p.u.	1.00	-	-
Point 2	PV Curve Point V2 Setting	PV_CURVE_V2-SS	V p.u.	1.10	1.06	1.10
	PV Curve Point P2 gen Setting	PV_CURVE_P2_GEN-SS	P p.u.	Pmin	Pmin	1.00
	PV Curve Point P'2 load Setting	PV_CURVE_P2_LOAD-SS	P p.u.	0.00	0.00	P'rated
P(V) Open Loop Response Time		PV_OLRT-SS	s	10	0.5	60

EPRI Note: *This function is typically disabled. However, it has been utilized on residential and shared secondaries as a simple mitigation where there is a concern of high voltages. Enabling this mode results in a reduction in output by active power curtailment when high voltage is sensed at the RPA.*

VOLT-ACTIVE POWER MODE (Volt-Watt Mode, P(V))		**EPRI Common File Format**	**UNITS**	**Utility-Required Setting**
Voltage-Active Power Mode Enable		PV_MODE_ENABLE-SS	Mode	{Disabled}
Point 1	PV Curve Point V1 Setting	PV_CURVE_V1-SS	V p.u.	{1.06}
	PV Curve Point P1 Setting	PV_CURVE_P1-SS	P p.u.	{1.00}
Point 2	PV Curve Point V2 Setting	PV_CURVE_V2-SS	V p.u.	{1.10}
	PV Curve Point P2 gen Setting	PV_CURVE_P2_GEN-SS	P p.u.	{Pmin}
	PV Curve Point P2 load Setting	PV_CURVE_P2_LOAD-SS	P p.u.	{0.00}
P(V) Open Loop Response Time		PV_OLRT-SS	s	{10}

6

DER RESPONSE TO ABNORMAL CONDITIONS

Requirements for DER response to abnormal conditions are specified in IEEE 1547-2018 clause 6 – Response to Area EPS abnormal conditions. The DER shall meet abnormal operating performance Category I, II, or III as identified in clause 6 of IEEE 1547-2018.

EPRI Note: *Moving from Category I to III widens the operating (ride-through) region of DER. Most modern inverter-based DER are capable of Category III operation and should include this capability in their certification.*

Table 6-1
Assignment of IEEE 1547-2018 Abnormal Performance Categories to Various Types of DERs

Power Conversion	Prime Mover/Energy Source	Category
Inverter	Solar PV, Battery Energy Storage, Fuel Cell, Wind	Category II or III
Synchronous and Induction	Bio-/Landfill Gas, Fossil Fuel, Hydro, Combined Heat & Power	Category I

EPRI Note: *Commonly used Categories per DER type are provided in table 6-1. Category selection should coordinate with bulk system needs and consider reasonable technology capability.*

6.1 Area EPS Faults

Requirements for area EPS faults are specified in IEEE 1547-2018 clause 6.2.1 – Area EPS Faults. For short-circuit faults on the Area EPS medium voltage, the DER shall cease to energize and trip unless specified otherwise by the Utility. This requirement is not applicable to faults that cannot be detected, such as high impedance faults.

EPRI Note: *IEEE 1547 addresses the concern of additional fault current from the DER during a MV fault. This is typically not a concern for inverter-based DER unless a grounding transformer has been added at the PCC. Also indicated is that ride-through is not required for local EPS faults. Most DER will contribute current to a faulted distribution system followed by cease to energize and trip if clearing the fault results in loss of mains. DER should not trip for transmission faults when voltage dips but is not momentarily interrupted.*

6.2 Open-Phase Conditions

Requirements for open-phase response are specified in IEEE 1547-2018 clause 6.2.2 – Open Phase Conditions. Three-phase DER shall detect, cease to energize, and trip within 2.0 s for any open phase condition occurring directly at the reference point of applicability.

EPRI Note: *Open phase detection will be a commissioning test requirement for most larger three-phase DER. In case of isolation from a MV RPA, such as a delta-wye connection, the DER must have MV sensing which can be used to detect the open phase.*

6.3 Area EPS Reclosing Coordination

Requirements for area EPS reclosing coordination are specified in IEEE 1547-2018 clause 6.3 – Area EPS Reclosing Coordination. Appropriate means to ensure that the DER does not expose the utility to unacceptable stresses or disturbances include the following or other relevant means: proper operating DER islanding detection, reclosing blocking on energized circuit, and transfer trip.

EPRI Note: *Removal of any unverified instantaneous reclosing is required to allow the DER time to cease to energize before utility reclosing. Options include either increasing the time delay to several seconds or the use of reclose blocking to verify the circuit is not energized. Both are commonly used to prevent out of phase reclosing. Low-cost alternatives have been used in switchgear with low power instrument transformers which allow equipment installation without major renovations. These methods may provide an alternative to direct transfer trip for high penetration of DER. Rotating machines often still require direct transfer trip. This requirement is relevant for the substation breaker and any automatic reclosing devices on the distribution circuit in front of the DER site based on the generation to load ratio in the isolated zone.*

6.4 Voltage Ride-Through Capability Requirements and Trip Settings

Requirements for voltage trip and ride-through requirements are specified in IEEE 1547-2018 clause 6.4 – Voltage.

DER, except for synchronous and induction machines, shall meet abnormal operating performance Category I, II or III as identified in IEEE 1547-2018. Synchronous and induction machines shall meet abnormal operating performance Category I.

The DER shall trip for default values of under and over voltage and clearing times as identified in IEEE 1547-2018 Tables 11-13 by category: for Category I, II or III.

Table 6-2
Voltage Trip Settings

Mandatory Voltage Tripping Characteristics ***EPRI Note****: Fill out below table and remove this reference table for TIIR implementation*		EPRI Common File Format	UNITS	IEEE Std 1547-2018 Category III		
				Default	Min	Max
OV2	HV Trip Curve Point OV2 Setting	OV2_TRIP_V-SS	V p.u.	1.20	-	-
	HV Trip Curve Point OV2 Setting	OV2_TRIP_T-SS	s	0.16	-	-
OV1	HV Trip Curve Point OV1 Setting	OV1_TRIP_V-SS	V p.u.	1.10	1.10	1.20
	HV Trip Curve Point OV1 Setting	OV1_TRIP_T-SS	s	13.00	1.00	13.00

UV1	LV Curve Trip Point UV1 Setting	UV1_TRIP_V-SS	V p.u.	0.88	0.00	0.88
	LV Curve Trip Point UV1 Setting	UV1_TRIP_T-SS	s	21.00	2.00	50.00
UV2	LV Curve Trip Point UV2 Setting	UV2_TRIP_V-SS	V p.u.	0.50	0.00	0.50
	LV Curve Trip Point UV2 Setting	UV2_TRIP_T-SS	s	2.00	0.16	21.00

Mandatory Voltage Tripping Characteristics		**EPRI Common File Format**	**UNITS**	**Utility Required Settings**
OV2	HV Trip Curve Point OV2 Setting	OV2_TRIP_V-SS	V p.u.	{1.20}
	HV Trip Curve Point OV2 Setting	OV2_TRIP_T-SS	s	{0.16}
OV1	HV Trip Curve Point OV1 Setting	OV1_TRIP_V-SS	V p.u.	{1.10}
	HV Trip Curve Point OV1 Setting	OV1_TRIP_T-SS	s	{13.00}
UV1	LV Curve Trip Point UV1 Setting	UV1_TRIP_V-SS	V p.u.	{0.88}
	LV Curve Trip Point UV1 Setting	UV1_TRIP_T-SS	s	{21.00}
UV2	LV Curve Trip Point UV2 Setting	UV2_TRIP_V-SS	V p.u.	{0.50}
	LV Curve Trip Point UV2 Setting	UV2_TRIP_T-SS	s	{2.00}

6.5 Frequency Ride-through Capability Requirements and Trip Settings

Requirements for frequency trip and ride-through are specified in IEEE 1547-2018, clause 6.5 – Frequency. The DER shall trip for default values, or as specified, for abnormal over and under frequency and clearing times as identified in IEEE 1547-2018 Table 18 – "DER response (shall trip) to abnormal frequencies for DER of abnormal operating performance Category I, Category II, and Category III".

The parameters of frequency droop operation shall be to their default values as identified in IEEE 1547-2018 Table 24. Frequency tripping and clearing times from IEEE 1547-2018 clause 6.5 shall be as specified in Table 6-3.

EPRI Note: If implementing "IEEE 1547-2018 default values" for any functions, it is a good practice to identify each setting point in the TIIR and associated sample settings files.

Table 6-3
Frequency Trip Settings

MANDATORY FREQUENCY TRIPPING CHARACTERISTICS	EPRI Common File Format	UNITS	IEEE Std 1547-2018 Category III		
			Default	Min	Max

EPRI Note: Fill out below table and remove this reference table for TIIR implementation.						
OF2	OF Curve Trip Point OF2 Setting	OF2_TRIP_F-SS	Hz	62.00	61.80	66.00
	OF Curve Trip Point OF2 Setting	OF2_TRIP_T-SS	s	0.16	0.16	1000.00
OF1	OF Curve Trip Point OF1 Setting	OF1_TRIP_F-SS	Hz	61.20	61.00	66.00
	OF Curve Trip Point OF1 Setting	OF1_TRIP_T-SS	s	300.00	180.00	1000.00
UF1	UF Curve Trip Point UF1 Setting	UF1_TRIP_F-SS	Hz	58.50	50.00	59.00
	UF Curve Trip Point UF1 Setting	UF1_TRIP_T-SS	s	300.00	180.00	1000.00
UF2	UF Curve Trip Point UF2 Setting	UF2_TRIP_F-SS	Hz	56.50	50.00	57.00
	UF Curve Trip Point UF2 Setting	UF2_TRIP_T-SS	s	0.16	0.16	1000.00

MANDATORY FREQUENCY TRIPPING CHARACTERISTICS		**EPRI Common File Format**	**UNITS**	**Utility Required Settings**
OF2	OF Curve Trip Point OF2 Setting	OF2_TRIP_F-SS	Hz	{62.00}
	OF Curve Trip Point OF2 Setting	OF2_TRIP_T-SS	s	{0.16}
OF1	OF Curve Trip Point OF1 Setting	OF1_TRIP_F-SS	Hz	{61.20}
	OF Curve Trip Point OF1 Setting	OF1_TRIP_T-SS	s	{300.00}
UF1	UF Curve Trip Point UF1 Setting	UF1_TRIP_F-SS	Hz	{58.50}
	UF Curve Trip Point UF1 Setting	UF1_TRIP_T-SS	s	{300.00}
UF2	UF Curve Trip Point UF2 Setting	UF2_TRIP_F-SS	Hz	{56.50}
	UF Curve Trip Point UF2 Setting	UF2_TRIP_T-SS	s	{0.16}

7 POWER QUALITY PERFORMANCE

Traditional power quality standards define expected voltage quality in the electric grid. DER operating in parallel with the grid should not degrade voltage quality under any operating or malfunction condition. Requirements for DER output power are intended to be more stringent than the requirements for customer load. This follows the principle that generation operating in the grid should be better behaved than load.

Given these expectations, IEEE 1547-2018, chapter 7, addresses power quality requirements for DER certification. Note these represent limits for DER in normal operation and do not apply to inadvertent mis-operation or failure modes. When installed, DER should not impact the delivered voltage quality of other customers on the grid.

Certification tests cover the DER dc injection, synchronization, harmonic current distortion, and load rejection overvoltage. There are also power quality requirements regarding DER-caused voltage fluctuations, flicker, rapid voltage change, and ground fault overvoltage. DER-related changes in grid voltage depend on the relative size of the DER and the strength of the grid and the PCC. Determining compliance usually requires either circuit analysis or measuring at the PCC during commissioning or in response to a voltage complaint.

The following specific power quality requirements address limits on DER voltage impacts when interconnected and operating in the grid.

7.1 Limitation on DC Injection

The DER should not inject dc current into the ac power system under any condition. IEEE 1547-2018 specifies a limit of 0.5% of rated current, and certified DER are assumed to meet this limit.

7.2 Limits on DER-caused Voltage Fluctuations

Voltage fluctuation limits depend on both the DER relative size and the strength of the grid (short-circuit MVA) at the PCC. The main concern is DER-caused fluctuations on the medium voltage power system. Requirements address rapid voltage change (RVC) as caused by switching large real or reactive power components, repeating power fluctuation causing flicker, and power changes that cause excessive voltage regulator operations. RVC and flicker limits are specified in IEEE 1547-2018 clause 7.2 – Limitation of Voltage Fluctuations Induced by the DER.

EPRI Note: *DER should be expected to provide fewer fluctuations and overall better quality than is required for customer load. The limits in IEEE 1547-2018 section 7 reflect this expectation. An informative annex in 1547-2018 provided additional practical information regarding what is expected from DER. Practical experience indicates an effective mitigation of DER-related voltage fluctuations is normally achieved by ensuring that the proposed grid connection point has sufficient capacity relative to the DER plant rating. For example, a stiffness ratio of >15, grid-short circuit power to the DER plant rated power (MVA_{SC}/MVA_{DER}) will likely minimize voltage impact. In cases of voltage complaints after plant installation, a certified power quality monitor will be required to diagnose any voltage issues and determine the cause and any* *required mitigation. In IEEE 1547-2003, power quality limits borrowed language from existing electrical service standards IEEE 519 and IEEE 1453. Since, IEEE 1547-2018 limits have been updated specifically for DER interconnection applications.*

7.2.1 Rapid Voltage Change (RVC) Limits

In normal operation the DER shall not cause RVC changes that exceed 3% ΔV at medium voltage and 5% ΔV when the PCC is at low voltage. Excluded are rare events such as transformer energization during a plant start-up or circuit restoration.

EPRI Note: *As of this writing, IEEE 1547-2018 is in the process of an updating to reconcile differences in the application of RVC in cases of DER as compared with IEEE 1453, which applies more generally. For DER applications, use the average change over one second. This is stricter than the defined duration in IEEE 1453.*

7.2.2 Flicker Limits

In normal operation the DER shall not cause repetitive changes of power output leading to voltage fluctuations that may can light flicker or other load impacts. To determine compliance, an allocation of the grid's flicker capacity at the PCC is provided to the DER. The allocation is Pst ≤ .35, based on a 10-minute assessment of DER-caused voltage fluctuations. Photovoltaic DER that is suspected of creating flicker violations, should be subject to a flicker assessment as part of a supplemental review.

EPRI Note: *Rapidly changing output is normally not expected from DER. An exception is solar PV with swiftly moving and broken clouds. This variability is known to depend on the plant size, with larger plants being less variable. Compliance relative to the flicker allocation limits can be estimated based on plant size, grid voltage response to power changes (aka stiffness), and the known worst case 10-minute variability in PV plants. Note that the Flicker limits for DER in IEEE 1547-2018 are more limiting than for load as defined in IEEE 1453.*

7.3 Limitation of Current Distortion

The DER should not cause an increase in voltage distortion at the PCC. If increased voltage distortion is observed additional monitoring, investigation, and mitigation may be required. This is not expected from certified DERs, however, unexpected interactions can happen.

7.4 Limitation of Overvoltage Contribution

The DER should not cause overvoltage that exceed limits defined in IEEE 1547. Overvoltage contribution refers to a single cycle overvoltage level of 138% for effective grounding limits and a cumulative instantaneous limit which is often used to alleviate load rejection overvoltage (LROV) concerns.

EPRI Note: *Certified DER are tested to confirm they meet the LROV limits. The GFOV limit test is an optional test and is less definitive since effective grounding is more dependent on the feeder details than on the DER.*

7.5 Limits on Unbalance

Three-phase DER installations shall not create current unbalance during normal conditions. The limit of periodic current unbalance is not to exceed 25% or any level that causes phase voltage in service to other users to violate limits for three-phase balance. Three-phase voltage unbalance in power service is typically limited to 2-3%, defined by:

$$Percent\ Voltage\ Unbalance\ = 100 \times \frac{Maximum\ Deviation\ from\ V_{ave}}{V_{ave}}$$

The largest capacity single-phase DER operating in parallel with the grid is limited by single-phase service transformer capacity. Up to {50 kW} may be allowed, so long as unbalance limits are not exceeded. Above that size, a balanced three-phase system is normally required. In cases of two-phase service, the three-phase DER limit will be determined by analysis of the available service and the DER. When three-phase service is available, a balanced three-phase connection shall be used.

8
UNINTENTIONAL AND INTENTIONAL ISLANDING

Requirements for DER islanding response are specified in IEEE 1547-2018 clause 8 – Islanding.

8.1 Unintentional islanding

Within 2 seconds of the formation of an island the DER shall detect the island and cease to energize the Area EPS. This time can be extended, at utility discretion, up to 5 seconds which can be beneficial to improving coordination between unintentional islanding detection and automatic reclosing.

***EPRI Note**: Detection of an island with inverter-based resources is different than with rotating machines due to the inverter's capability to actively perturbate the island leading to voltage or frequency limit trip. Experience has shown that inverter islands are only possible with a very specific set of circumstances related to the balance of real and reactive power within the island. Rotating machines rely on relays and passive detection methods (such as distortion levels or impedance changes), these are less effective and therefore usually require an external, utility-controlled method with communication, such as transfer trip or measured changes in phase and/or frequency.*

The customer can be required to identify and disclose the method of island prevention that is being used for all DER above x kW (x is typically 250kW). Criteria to evaluate suitable prevention of unintended islanding are described for the technical review process in chapter 3. Additional discussion on islanding detection with respect to PCC and feeder compatibility are covered in Chapter 11.

8.2 Intentional Islanding

Intentional islands can be one of two types: 1) an Intentional Area EPS Island, which includes any portion of the Area EPS (i.e., multiple utility customers), and shall be designed and operated in coordination with the Utility when islanded; and 2) an Intentional Local EPS Island, or Facility Island, which is totally within the bounds of the local EPS (i.e., a single utility customer electrically connected at a single PCC) during the intentional island condition. The requirements outlined within this section pertain to the second type, a customer- or third party-owned and operated Intentional Local EPS Island.

The customer shall bear all responsibility for energy management, service, safety, power quality, and plant operation during island mode, where island mode means isolated from the {UTILITY} Area EPS.

DER configured to support intentional islands shall disconnect from the {UTILITY} system by microgrid interconnect device (MID) in accordance with NEC Article 700.

Any DER interconnecting with intention to operate as an intentional island shall be equipped with a multi-mode system[8] consisting of stand-alone capable DER and MID. In cases where the DER is a simple, single unit, the DER and MID shall be tested together and certified to UL 1741 SB, including UL 1741 CRD for Multimode. In accordance with UL 1741 CRD for Multimode, such systems may employ open or closed transfer when switching between sources.

- Closed transition designs shall be limited to 100 ms of parallel connection.
- Combinations of DER and MID shall conform to anti-islanding provisions of IEEE 1547-2018.
- Systems where the RPA is the PCC or Composite DER Systems[9] shall be subject to additional commissioning and witness testing to demonstrate isolation during island mode and return to service.

EPRI Note: *It is generally practical for small scale systems (RPA at PoC) to require that the DER and MID are tested together to receive UL 1741 listing. In many cases, vendors provide equipment packages (e.g., PV + storage with controller) which are designed and tested to operate in union. For larger systems, this sort of functionality is more bespoke and involves inverters from one manufacturer, a protective/islanding relay from another, and breaker/recloser from a third. As such, for systems that use parts from separate vendors that were not tested and listed together, a logic review and an onsite witness test should be required.*

Note that standards are developing in this area, UL CRD for Multi-mode may be superseded by UL 3010.

An intentional island is outside of grid control but does have a pre-defined electrical boundary and could be a facility island or a microgrid. As a group of DER that connect to the grid, a microgrid is obliged to at least the same interconnection requirements as individual DER. Variability of site configurations, different DER types and the expectation of on and off grid transitions may require additional technical review before approval of interconnection. EPRI report, Grid Considerations for Microgrids (3002020344), provides additional details on the complexities.

Generators and battery systems which utilize an automatic transfer switch and are designated stand-by or emergency backup shall not, under any circumstances, parallel with the area EPS. These systems are outside the scope of these requirements.

8.2.1 Conditions for Transitions to Intentional Island

The conditions under which intentional island DER may disconnect from the Area EPS and transition the DER to intentional island mode are covered in IEEE 1547-2018 clause 8.2.2.

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[8] Multimode system means DER capable of operating in parallel with the area EPS and independent support local load during an outage.

[9] Composite DER: Systems which meet IEEE 1547-2018 compliance through various supplemental DER devices such as micro grid or plant controllers, relays, and reactors.

Practically, an intentional island enables customer loads to be supported by customer DER during abnormal system conditions—conditions when DER, per IEEE 1547-2018, would otherwise trip. Examples of abnormal system conditions include, fuse blowing or recloser lockout due to system faults on distribution primary, rolling blackouts for wildfire mitigation, or during sustained large area supply constrained events.

The system operator's primary concern is that the DER separates and does not energize any area system network as service restoration work is underway.

8.2.2 Reconnection of an Intentional Island to the Area EPS

The return to service conditions in section 4.7 shall be met prior to an intentional island reconnecting to the Area EPS.

8.2.3 Adjustment to DER settings

Control and protection settings may have to be adjusted when operating in an intentional island. DER shall demonstrate the capability to revert to the settings issued by {UTILITY} for parallel operation.

8.2.4 Commissioning and Witness Testing

DER configured for and applying with intentional island capability may be subject to additional commissioning and witness tests to demonstrate the applicable additional capabilities.

9

FACILITY INTEROPERABILITY AND CYBER SECURITY

9.1 General Requirements

All DER shall meet the requirements for interoperability as specified in IEEE 1547-2018 clause 10 – Interoperability, Information Exchange, Information Models, and Protocols.

This section defines specific requirements for {UTILITY} and clarifies which systems must be connected to telecommunications networks for monitoring and control purposes.

9.2 DER Local Communication Interface

9.2.1 DER Requirements

All DER shall have a local DER communication interface meeting the interoperability requirements specified in IEEE 1547-2018 clause 10 – Interoperability, Information Exchange, Information Models, and Protocols.

9.2.2 Communication Interface Onsite Physical Presence

The DER local communication interface shall be a wired interface as specified in IEEE 1547-2018 Table 41. This wired interface shall be physically present at the DER site, having no dependencies on internet or other network connectivity and no dependencies on cloud or other offsite systems.

EPRI Note*: There remains a lack of understanding among some DER providers that a local physical interface is required versus, for example, the "local" ability to connect to a remote cloud interface. Some products have arrived in field locations lacking a local interface.*

9.2.3 Single Communication Interface for a DER

In accordance with IEEE 1547-2018, {UTILITY} requires a single communication interface for each DER. It shall not be acceptable for separate communication interfaces to be provided for parts of a DER, for example at each inverter in a multi-inverter DER plant.

Monitoring and Nameplate information read through the single communication interface shall be representative of the plant, not a part or portion thereof.

Control settings and functions shall be relevant to the DER as a whole and the associated single reference point of applicability such as the PCC or electrical point of connection. For example, with a multi-inverter DER plant, the control settings for the Volt-VAR function shall apply to the voltage and reactive power at a single point, the RPA and not to multiple points of measurement at each inverter within the DER.

***EPRI Note:** In some cases, DER developers have attempted to omit plant controllers and provide only separate communication and control interfaces for each inverter within a larger DER plant.*

9.2.4 Local Communication Interface Labeling

{UTILITY} requires that the standard local communication interface be labeled at each DER site such that it is readily locatable and identifiable. The label shall state "IEEE 1547-2018 Local Communication Interface" and shall name the standard protocol by which the DER was certified.

For interconnection applications that involve a site plan, the physical location of the local communication interface shall be identified on the plan.

EPRI Note: *Some DER that have been certified to IEEE 1547-2018 and UL 1741SB provide no indication of which port or interface is the standard one. In some cases, there is no reference to a standard interface in the manual or documentation and no awareness of it with manufacturer technical support. The purpose of this requirement is such that it can be located with a reasonable effort.*

9.2.5 Communication Interface Availability

The DER local communication interface shall be present and available for DER as and when deployed and shall remain in place for the life of the DER. All hardware required shall be present and no additional equipment shall be needed to make the local interface operational.

No DER equipment changes shall be needed to access or activate the local communication interface such as jumpers, switches, wire-splicing, or mechanical modifications.

EPRI Note: *Some DER that have been certified to IEEE 1547-2018 and UL 1741SB arrive in the field lacking hardware elements necessary to provide the local interface. These DER vendors interpret the IEEE 1547-2018 requirement that the interface be "available" as being met because the additional hardware can be ordered at any time.*

9.2.6 Communication Interface Operability

{UTILITY} requires that the standard local communication interface not be locked, disabled, or otherwise unresponsive to communication as specified by the standard communication protocol for which the DER is certified. No vendor-proprietary setup, configuration, password mechanisms, remote procedures and customer actions may be required to make the communication interface operational and responsive.

As specified in IEEE 1547-2018, Table 42, "The local DER communication interface shall be active and responsive whenever the DER is operating and in a continuous operation region or mandatory operation region".

EPRI Note: *Prior to the creation of IEEE 1547-2018, some DER designs had methods to lockout communication on local interfaces, usually with passcode or other consumer actions required. Some vendors have attempted to continue this practice even after open access is required. Proprietary steps to unlock a DER is only allowed for the initial set up and for certification. The open standard protocols do not support this and cannot unlock a DER that has been locked using proprietary means.*

9.3 Right to Utilize DER Communications

{UTILITY} reserves the right to make use of the DER communication capabilities for monitoring and control purposes.

9.3.1 Utilization Onsite or Remote

The communication may be performed onsite during commissioning or subsequent visits to check or adjust plant settings. This may be performed using {UTILITY}'s software tools connecting to the DERs standard local communication interface.

The communication may be performed remotely. This may be performed using fixed networks that are deployed by {UTILITY} connecting to the DERs local communication interface.

9.3.2 Utilization Upon Interconnection or Thereafter

{UTILITY}'s utilization of the standard local communication interface may be immediate, during or upon interconnection or subsequently at any time over the lifecycle of the DER.

9.4 DER Local Interface Protocol

IEEE 1547-2018 clause 10.7 – Communication protocol requirements recognizes that {UTILITY} may specify the required protocols at local DER communication interfaces from among the three standards identified in Table 41.

{UTILITY} specifies the required protocols on the local communication interface based on criteria identified in **Error! Reference source not found.**.

Table 9-1
Assignment of IEEE 1547-2018 Local DER Communication Interface Protocols to Various Types of DER

Criteria 1: DER Size	Criteria 2: Power Conversion	Examples	Required Protocol
Small scale	Inverter	Residential and small commercial Solar PV, Battery Energy Storage or EVSE with V2G capability	{SunSpec Modbus}
	Synchronous generator	Small industrial and independent power producer bio-/landfill gas, fossil fuel, hydro, combined heat & power	{IEEE 1815 (DNP3):AN2018-001}
Large scale	Inverter	Solar PV, Battery Energy Storage	{IEEE 1815 (DNP3):AN2018-001}
	Synchronous generator	Industrial and independent power producer bio/landfill gas, fossil fuel, hydro, combined heat & power	{IEEE 1815 (DNP3):AN2018-001}

EPRI Note: *Identifying specific protocol requirements based on DER type/size greatly simplifies communication-integration going forward. DER manufacturers are provided with clear requirements. SunSpec Modbus is by far the most common protocol supported by DER manufacturers. For larger DER that may be SCADA-connected, DNP3 may be the only possible choice due to the nature of these systems. Use of SunSpec Modbus at the DER local interface and conversion to DNP3 in the DER gateway may be an alternative.*

EPRI continues to evaluate DER interoperability through the DER Interoperability Initiative. SunSpec Modbus, due to its relative simplicity, is the most interoperable. More complex protocols, like IEEE 2030.5, are useful inside utility communication systems (e.g. between headend and gateway) but are not practical choices at local DER interfaces where hundreds of companies must interoperate.

9.5 Communication Network Connectivity

{UTILITY} requires the following default communication network connectivity. Additional requirements may be established on an as-needed basis.

- DER of {500} kW or smaller will not be connected to the utility communication system initially. However, {UTILITY} reserves the option to interconnect at a future date.
- DER greater than {500} kW will be connected to the utility communication system at the time of interconnection. This communication connection will be used to support telemetry, monitoring, and control requirements in accordance with the interconnection agreement.

9.6 {UTILITY} DER Network Adapter (DER Gateway)

For DER interconnections that require a {UTILITY} communication network connection, {UTILITY} will provide and install, at customer cost, a DER gateway that connects to the DER's standard local communication interface.

9.6.1 Gateway Inspection and Maintenance

{UTILITY} reserves the right to access the DER gateway for inspection, reconfiguration, and maintenance purposes. {UTILITY} reserves the right to replace the DER gateway, at {UTILITY}'s cost, as needed over the life of the DER.

9.7 DER Cyber Security

EPRI Note: *DER are assumed to be compromised by design, manufacture, supply-chain, operator/owner, and internet connection. From a system design perspective, the DER gateway serves as the edge-most element of the utility's system.*

Many small DER, if compromised and/or manipulated together, pose similar risks as a single large DER. Accordingly, it would be preferable from a grid-perspective to prohibit secondary communication interfaces and unauthorized firmware updates for all DER. However, consumers and DER manufacturers receive benefit from having access to the DER with information interactions that utility networks are generally not-yet able to support. The recommendations below represent a compromise between these points.

The cyber security requirements set forth in IEEE 1547.3 generally apply to the control systems for DER, from headend systems and users to networks and edge gateways and not the DER itself as interconnected.

9.7.1 Secondary Communication Interfaces

DER greater than {500} kW is prohibited from having additional remotely accessible communication connections to plant controllers, inverters, protective devices, or other equipment capable of affecting the power behavior of the DER. Communication connections to metering devices for remote monitoring purposes is permitted.

9.7.2 DER Firmware/Software Updates

DER {500} kW or smaller may be firmware/software updated by the DER vendor, owner, or operator, either onsite or remotely, as required.

DER greater than {500} kW shall require informing {UTILITY} and receiving approval prior to any firmware/software updates.

For all DER sizes, DER configuration and settings must be retained or restored when any firmware/software update takes place.

10
COMMISSIONING AND VERIFICATION REQUIREMENTS

10.1 General Requirements

Verification requirements (design evaluation, as-built submittals, configuration settings, and commissioning tests) are specified in IEEE 1547-2018 clause 11 – Test and Verification Requirements and in Appendix F, Discussion on Testing and Verification.

This chapter provides several steps supporting verification that the plant interconnection meets requirements in addition to those identified in IEEE 1547-2018. The verification process includes configuration of the DER's functional and protection settings, DER As-Built Evaluation (also referred to as Installation Evaluation), commissioning and witness testing. References to determine test requirements that depend on the facility size and type, as well as any specific protective relay test requirements are provided. This chapter also covers recommissioning and periodic testing.

EPRI Note: *It is recommended that utilities use the Common File Format for DER Settings Exchange and Storage to specify and read applied inverter settings.*

Specific requirements for each project will be communicated to the customer/developer. These requirements will be a subset of the items found in this chapter.

10.2 DER Commissioning Process

Commissioning and verification requirements are specified in IEEE 1547-2018 clause 11 – Test and Verification Requirements.

1. Customer shall notify {UTILITY} upon completion of construction and submit As-Built documentation.
2. {UTILITY} will conduct an Installation Evaluation, confirming that installation as built matched the approved design and a review of DER settings.
3. A pre-commissioning and commissioning/witness test plan will be provided by {UTILITY} of by the customer to be conducted within an agreed upon timeframe.
4. Upon completion of pre-commissioning tests, customer shall notify {UTILITY} and provide test results. If determined to be satisfactory by {UTILITY}, the commissioning / witness test will be scheduled and conducted by mutual agreement.

10.2.1 Verification of the DER Settings

{UTILITY} specified DER facility settings are provided in Appendix G and are available for download from EPRI's DER Performance and Settings Database.[10]

Prior to commissioning tests, the Customer shall configure the DER facility's settings by means of one of the following options:

- Option A: Using local or remote vendor configuration tools.
- Option B: Using a configuration and validation toolkit that uses the *local DER communication interface*.[11]
- Option C: Integrating through a DER gateway with the utility DER management system (DERMS).

10.2.2 Installation Evaluation

Prior to the performance of commissioning tests by qualified personnel, {UTILITY} will evaluate the as-built documentation to confirm that it is consistent with the application and other required project documentation. This installation evaluation is intended to determine whether commissioning can proceed and the level of commissioning that is required. Certain commissioning tests may need to be completed by the Customer before Witness Testing can take place.

10.2.2.1 Review to Confirm As-Builts

The as-installed DER equipment information is required before witness testing for confirmation of consistency with previously provided documentation. This information shall be supplied for the installed DER system and for all DER equipment. This should apply to all systems to ensure the DER system of record includes an accurate accounting of the equipment used in the project as built, and that operational capacities align with operating agreements.

10.2.2.2 Documentation and Reporting of DER Functional Settings

The customer shall provide verification that the plant has been programmed according to the settings profile requirements issued by {UTILITY}. This may be done by (a) providing a serialized, time stamped EPRI common file format read from the DER, (b) filling out a confirmation form provided by {UTILITY}, or (c) read by qualified personnel at the *DER local interface*.

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[10] https://dersettings.epri.com/

[11] EPRI. Common File Format for Distributed Energy Resources Settings Exchange and Storage. Palo Alto, CA: 2022. 3002025445. https://www.epri.com/research/products/000000003002020201

10.3 DER Commissioning Tests

The DER facility commissioning process shall be planned and carried out by a qualified party approved by {UTILITY} after construction is completed, installation as-built evaluation is satisfactory, and the site is ready to be energized. The commissioning process shall verify that the plant meets the requirements of this document.

EPRI Note: *Practically, both the utility and developer may agree to a test plan, determined by the system design and requirements of the utility. The Facility Commissioning Tests may be executed without the utility present, and resultant test reports provided to demonstrate performance. This is more common for smaller sites. Additional witness testing may be performed later as a final step if required.*

Another approach is to list procedures and issues for the developer to perform. For experienced and qualified engineers overseeing larger plant commissioning, simply state what performance criteria will need to be evaluated. In these cases, the procedure should be reviewed and approved by the utility prior to test plan execution. For reference, a 2019 survey of EPRI member utilities reported that 40% of commissioning tests are conducted by utility staff and 20% depended on developers and third parties to conduct commissioning tests. The remaining 40% of responses contained combinations of developer, utility, and third-party.

10.3.1 Facility Commissioning Tests

Commissioning requirements are dependent on the size of the DER, DER certification, and whether the RPA is at the PCC or PoC as identified in IEEE 1547-2018. Table 10 summarizes detailed and basic commissioning tests for various classes of DER.

EPRI Note: *For additional guidance on determining RPA and recommendations for test plan, refer to EPRI report 3002028376: DER Performance Verification and Commissioning Guideline: Utility Current Practices and EPRI Recommendations.*

Assessment of power quality performance can be challenging to conduct as part of commissioning or witness testing given that violations may manifest under unique grid conditions. Where performance is in question, deployment of a temporary PQ meter for several weeks to evaluate various DER output against various grid conditions may be practical. Some companies require permanent PQ quality metering at certain capacity thresholds of DER.

Table 10-1
Example Commissioning Test by Category

Commissioning Test	Basic Commissioning	Detailed Commissioning
As-built Verification	{X}	{X}
Protection Relay/DTT		{X}
SCADA/Metering (Telemetry)	{X}	{X}
Cease to Energize/Loss of Grid	{X}	{X}

Permit Service Signal	{X}	{X}
Enter Service Ramp		{X}
Open Phase Detection/Open Phase Overvoltage Test		{X}
Power limit function (as applicable)	{X}	{X}

Clause 11 of IEEE 1547-2018 provides a commissioning requirements matrix. Commissioning tests shall be performed by qualified personnel. For DER systems with plant controllers, commissioning tests shall include the plant controller. The results of the commissioning tests will be evaluated by {UTILITY} before Witness Testing can take place.

In addition to the commissioning test requirements identified in IEEE 1547-2018, DER settings shall be verified and protective relaying shall be tested as identified in Section 13.4.2 – Protective Relay Tests. Commissioning is also required for telemetry systems depending on DER size and application. Witness testing for spot- or area network-connected DER shall include a {UTILITY} System Protection/Telecom point-to-point testing of any protection scheme.

Example commissioning test checklists can be found in Appendix E and Appendix F.

10.4 Protective Relay Tests

Qualified testing personnel must perform tests on the Customer's protective relaying prior to energizing from the {UTILITY} system (see Table 10-2). Testing requirements will be evaluated and determined on a case-by-case basis by the Utility, dependent upon the configuration of the proposed generating facility. Portions of the Customer's equipment may be energized when the associated testing for that portion has been completed and verified.

Table 10-2
Example Testing Requirement for Relay Equipment

Relay Equipment Testing Requirement	Type of Testing
Protection Device Function	Variable – Determined by Relay Type
Acceptance Testing	Test Document Review
Setting Calibration	Witness/Functionality
Tripping Check	Witness/Functionality
Sensing Devices	Test Document Review
Primary Current/Voltage	Witness/Functionality
Telemetry for Protection Scheme	Witness/Functionality

The configuration of settings for the protection systems shall be the settings previously provided by the Customer approved by {UTILITY}. These settings shall not be altered during commissioning without the authorization of {UTILITY}.

10.5 Witness Testing

Before parallel operation with the Utility System, and after completion of commissioning tests, additional witness testing may be required and inspected by Utility. The Customer is responsible for providing qualified personnel who will complete all required tests. Witness testing is generally required for larger DER. Utility reserves the right to require witness testing in all DER Interconnected scenarios. Witness tests that must be performed in accordance with requirements described above include:

- Cease-to-energize and trip test
- Anti-islanding
- Reconnection test
- Power Limit functions test
- Telemetry/SCADA (If applicable)
- Primary Metering
- Direct Transfer Trip (If applicable)
- Reverse power relay (If applicable)

Witness testing for spot or area network-connected DER shall include a {UTILITY} System Protection/Telecom point-to-point testing of any protection scheme.

EPRI Note: *Providing an itemized list of the tests to be demonstrated during on-site witness testing is a recommended practice. The utility should determine which tests are practical for witness testing.*

10.6 Recommissioning

Recommissioning is required, under certain circumstances, after the original commissioning and witness testing is completed. The extent of recommissioning is dependent on the reason for the commissioning and the effect on the DER interconnection.

Circumstances that may lead to event-based DER recommissioning include:

- Change in software versioning, software or parameter modifications that change rated values;
- Replacement of major components or modules with a new version;
- Required changes in the facility telemetry, or changes in major equipment (e.g. transformers, circuit breakers, etc.);
- Change in operating mode that was not previously commissioned.

Recommissioning may be triggered based on notification of facility change requirements, and may occur due to automated notices of operation outside of expected parameters. These notices may include mis-operation of the DER, mis-operation of protective systems, or excess harmonics detected at the PCC. {UTILITY} will determine whether recommissioning may require the full set of tests required of a new facility or if a subset of these tests will be sufficient. The level of testing is dependent on the reason for the recommissioning.

10.7 Periodic Testing

Periodic testing may be required as part of the regular testing of basic functionalities of protective and control functions. Test frequency is determined by manufacturers recommendations and {UTILITY} experience with similar equipment. Timeframes are indicated in Table 10-3.

The Customer must provide {UTILITY} with calibration and functional test data for the associated equipment upon request. Minimum intervals are indicated below.

Table 10-3
Periodic Testing Requirements

Device	Frequency
Relays	{1 – 10 years}
Communication Channels	{1 – 10 years}
Circuit breakers	{3 – 10 years}
Batteries[12]	Per IEEE 450-2020 Standard

The customer must include the identities and qualifications of the personnel who performed the tests. Utility personnel may need to periodically witness the testing.

[12] Vented lead-acid batteries for stationary applications that are used in DER design.

11
DISTRIBUTION SYSTEM COMPATIBILITY

11.1 DER Integration Compatibility with the Grid

This chapter describes DER and feeder hosting capacity and compatibility considerations and limits. They apply to both individual DER at a PCC and aggregate DER on a feeder. Included are guidelines to avoid thermal, voltage, or protection impacts from radial- or network-connected DER. {UTILITY} will provide the bus and line configurations and hosting capacity requirements that are necessary to connect the proposed DER. Requirements for a specific facility may be different than those listed based on existing system conditions, DER type, and/or DER size.

Typical compatibility requirements for all sites are covered in this chapter. Examples of relay and relay functional requirements for different types and sizes of DER facilities are listed in Appendix D. Typical one-line diagrams are, meanwhile, displayed in Appendix B. This provides basic information on the types of protection schemes necessary for DER interconnection.

11.2 Grid Integration for Radial-Connected DER

Integration requirements for radial-connected DER address the compatibility of the DER facility at the PCC and along the distribution feeder. Feeder voltage regulation, protective relaying, short circuit coordination, reverse power requirements are among compatibility considerations. Requirements depend on the DER type, location, existing conditions, and feeder capacity.

The objective of requirements is to maintain service voltage within limits for all customers. This includes operating equipment within equipment power limits, managing reverse power, coordinating protection, and addressing contingencies requiring feeder reconfigurations. In this section, possible modifications to the distribution system are addressed which can mitigate DER impacts to the system.

11.2.1 Thermal Operating Limits

An interconnection shall not thermally overload any electrical equipment based on ratings and industry practices for determining limits. Thermal limits shall be based on both individual and aggregate DER system ratings, as well as the feeder loading. DER plant level export limiting systems may be used to mitigate overloads. Managing active power may be required to assure that thermal limits are not exceeded.

11.2.1.1 Conductor Limits

{UTILITY} will evaluate interconnecting DERs at the export limit capacity while considering feeder loading according to minimum load data (daytime for PV power systems) to ensure feeder conductors do not exceed current ratings. Aggregate DER capacity less minimum loading cannot exceed conductor ampacity at any point along a feeder.

EPRI Note: *Available minimum load data, forecasted load changes, related planning criteria, and engineering judgement should be used to determine thermal limits on hosting capacity and future available headroom at any point on a radial feeder.*

11.2.1.2 Substation Power Transformers Limits

The aggregate DER capacity will be limited to {ranges from 50%-100%} of the substation transformer normal rating. In the case of parallel substation transformers, aggregate DER capacity shall be limited to the value of the substation transformer normal rating of the smallest transformer.

EPRI Note: *Minimum load can be considered to determine reverse power limits. This practice will allow DER to backfeed to subtransmission/transmission during low load times, where DER generation exceeds minimum load. Note that small systems may continue to be interconnected when the substation transformer limits are reached.*

11.2.1.3 Distribution Service Transformer Limits

The DER interconnection requires a change in the service transformer if the aggregate DER output is greater than {typically 60%-100%} of the transformer nameplate rating. Also, secondary conductors may require upgrade to avoid thermal limit or excessive voltage drop issues.

EPRI Note: *Large amounts of residential PV on a shared secondary can result in thermal and overvoltage issues. Secondary overvoltages can result in PV cycling on/off. Engineering options include increasing the size of the transformer, reducing the quantity of shared services, or using Volt-Watt smart inverter functionality in the DER.*

11.2.2 Short Circuit Limits and Coordination

The short circuit limit of all protective devices (e.g., breakers, reclosers, and fuses) across the {UTILITY} distribution system will be evaluated at {typically 90%} of their interrupting rating.

In addition, all DER interconnection requests that increase the effective three-phase or single-phase to ground short circuit current of the system, at any location, by {typically 10%} or more will require a review of the protection coordination in the Area EPS to ensure that proper coordination can be maintained.

EPRI Note: *The intent of the interrupt rating evaluation is to ensure that no equipment exceeds its rated interrupting capabilities. If the existing fault current level on the circuit is already near the limit, then a detailed study may be required to analyze the fault current projections and identify specific equipment with insufficient ratings.*

A short circuit current evaluation is to identify how protection coordination may be impacted by adding DER. Inverter DER fault currents are typically low enough to not impact time overcurrent coordination on a feeder. Rotating machines and plants with supplemental grounding may surpass this limit and require a more detailed coordination review.

11.2.3 Voltage Limits

11.2.3.1 Steady State Voltage Limits

For systems which do not pass screens and require detailed study, a load flow simulation is performed to evaluate if voltage on the circuit will remain within the C84.1 Range A limits. An interconnection is evaluated for peak and minimum loads for normal operating conditions. Abnormal conditions are not accounted for.

EPRI Note: *High penetration of DER can cause high voltage on the circuit during periods of reverse power flow. Depending on the results of the load flow analysis, further actions may be required. Example actions include adjusting the LTC/regulator settings, utilizing a non-unity power factor, applying smart inverter voltage settings, reducing DER size, and adding or relocating capacitors and regulators.*

11.2.3.2 Voltage Fluctuation Limits

This metric is used to represent the DER generation impact on distribution feeder voltage. It quantifies the difference in feeder voltage between the DER system at full output compared to sudden loss of generation. A DER-caused change in feeder voltage should not exceed 3%. The primary determining factor is relative size of the DER compared to the feeder short circuit MVA at the chosen PCC. Voltage impact is greatly influenced by distance from a substation. If the 3% criterion cannot be met with power factor mitigation, an impact study, line reconductoring, or reduction in DER size may be required. This is to ensure that voltage can be maintained within applicable standards.

EPRI Note: *Large DER on a weak system can cause excessive voltage fluctuation during swings in power output. Further review may be required when voltage fluctuations are predicted. Typical mitigations include adjusting the LTC/regulator settings, utilizing a non-unity power factor, applying smart inverter voltage settings, reducing DER size, and adding or relocating capacitors and regulators.*

11.2.4 Reverse Power Flow Limits

Aggregate DER capacity shall not create reverse power flow that exceeds the ratings of any electric system components or those not capable of reverse power flow. Electric system components can include transformers, LTC equipment, voltage regulators, network protectors, protective relaying, and substation metering.

Reverse power flows shall not be allowed where it may impact LTC equipment, negatively impact {UTILITY} transformer health, or create additional protection requirements. An estimate of minimum load will be used in reverse power calculations.

Where transmission or sub-transmission have constraints. DER backfeed potential shall be evaluated. DER export capacity may be limited.

EPRI Note: *Minimum load can also be used in the calculation of the reverse power flow through the devices. Some devices may be made capable of reverse power flow by setting changes, a re-evaluation of their control scheme, or replacement. For example, for PV systems, the lowest daytime load (9am - 3pm) going through the lowest loaded phase of a voltage regulator or* *distribution power transformer must be 20% greater than the aggregate solar output downstream of the respective equipment; otherwise, mitigation is required.*

11.2.5 Substation Ground-Fault Overvoltage (GFOV)

Area EPS with delta-wye substation transformers and a high generation to load ratio can result in transmission system overvoltages during a transmission ground fault. Due to the transformer winding configuration, the distribution system cannot contribute zero sequence ground fault current for this fault. This results in phase to ground overvoltages after the utility transmission line breakers are opened, which can exceed insulation levels of the substation and transmission line equipment.

DER capacity beyond {typically 50%-80%} of the load in the system will require substation modifications to install a 3V0 protection scheme. A 3V0 protection scheme consists of potential sensing on the transmission system and trips the low side substation breakers to isolate the distribution system and DER from the fault.

EPRI Note: *The lack of zero sequence continuity in most substation transformers prevents DER visibility to ground faults above the Area EPS substation. A 3V0 (or 59N) relay scheme will allow the utility to isolate the DER from the upstream fault. Many utilities will trip either a low-side breaker or the feeder breakers in this scenario. This reduces complexity instead of DTT to every DER on the system. Sequential tripping will disconnect the DER from the distribution system with either anti-islanding protection or frequency/voltage elements once the feeder breaker is open.*

11.2.6 Plant Relay Protection (or built-in protection functions)

The protective relaying requirements are dependent on the DER type and the characteristics of both the site and feeder. The relay functionality is determined based on which can provide protection for faults internal to the DER site and for Area EPS faults.

DER protection systems shall include overcurrent protection for internal faults on the DER equipment, including any customer-owned interconnection transformers. This protection shall be coordinated with {UTILITY}-owned upstream protection devices for large, front-of-the-meter, installations.

Protective relaying will trip and disable reclosing for faults internal to the DER plant.

Typical protective relay functional requirements are in Appendix D.

EPRI Note: *The protective functions in the inverter are typically considered as the primary relay protection for anti-islanding protection. For larger sites, some utilities require a backup set of relaying, or it may be covered in the utility-owned PCC recloser. Additional protective relaying will be required at the RPA in cases where inverter-based sensing is not sufficient to detect Area EPS faults based on lack of zero sequence continuity to meet 1547-2018 requirements. Rotating machines will drive additional functionality due to the possibility of higher fault currents and negative sequence contribution.*

Overcurrent protection for faults within large DER facilities should coordinate with utility protection. In the case of high DER penetration, existing mainline fusing on the utility system *typically requires replacement with three-phase tripping devices. DER overcurrent should not violate ride-through requirement for faults on the utility system outside the required zone of protection. For example, customer-owned voltage restrained overcurrent should not be set to prohibit ride-through requirements.*

Systems with non Yg-yg transformers and larger DER (>2MW on 15kV systems) will likely have MV relaying or a customer-owned PCC recloser. Fuses on larger sites are not common due to miscoordination and potential for single phasing which can cause ferroresonance.

11.2.7 Utility-Owned Recloser at PCC

Utility-owned reclosers are required on all medium voltage interconnected DER {typically 500kW to 1MW or greater}.

EPRI Note: *From field experience, both a utility- and a customer-owned recloser is commonly required to address feeder and plant protection objectives for large, front-of-the-meter DER installations. The utility-owned device provides remote monitoring and control. Protection settings in the utility-owned recloser vary by utility and can include overcurrent, voltage, frequency, and/or reclosing functionality.*

11.2.8 Compatibility with Distribution Automation ("DA") Schemes

The DER shall not interfere with Distribution Automation (DA) schemes. Where DERs may interfere with existing DA schemes, the following design requirements shall apply:

- DERs applying within DA zones shall not interfere with the proper operation of the scheme. The range of load and DER output levels must be maintained to ensure proper operation under all conditions. Mitigation techniques may be necessary to meet this requirement.
- DERs proposed within existing protection and automation schemes must be integrated and interoperable to maintain existing levels of reliability.

11.2.9 Special Case – Direct Transfer Trip Protection

Direct Transfer Trip (DTT) protection may be required for synchronous and induction generators, and for larger inverter-connected DER installations. Considerations for synchronous generators are different than inverter based.

EPRI Note: *DTT can be installed to ensure the DER is offline for specific utility conditions and to prevent out of phase reclosing. Other options that are used include reclose blocking and delaying the reclose time, which have become common with active anti-islanding and the growing number of installed inverter-based DER. The additional DTT system would be utility grade components with dedicated communication lines. The EPRI Islanding Prevention Risk Assessment Tool (IPRAT) can be used to consider site-specific conditions to quantify the probability of an island condition. From field experience, a wide range of practices are being employed regarding DTT in different areas.*

11.2.10 Special Case - Dual Utility Service (Normally Open)

For customer locations where switchgear is equipped with alternate feeds, and where automatic-transfer capability is employed, protection shall be provided to block the transfer while DERs are paralleled to the system to prevent an out-of-phase condition. In addition, if required protection is not installed on the customer alternate source, the DER will be tripped before the customer is transferred to the alternative source.

11.2.11 Special Case - Restricted Capacity Circuits

Any distribution circuit will have an upper limit to the amount of distributed generation that can be accommodated. When the installed generation on a circuit has reached its maximum, (generally just before the point of thermal or voltage violations), no further interconnection applications can be accepted for DER's, regardless of size, unless the customer is willing to pay for the needed upgrades. Typically, this is done after large systems have taken a considerable amount of the hosting capacity to avoid closing the circuit entirely to smaller systems.

Potential DER owners may request, at their expense, to pay for upgrades that would allow them to install their system. In many cases, the required upgrade costs may make an installation cost prohibitive. An alternative to upgrades may be DER export control or export limiting based on timing or another agreed criterion.

11.2.12 Special Case - Buffer Zone Capacity Limits

Buffer zones may be set around specific DER integration requirements such as current levels, individual or aggregate DER capacity, and reverse power kVA limits. Buffer zones indicate nearing or exceeding a limit and provide a margin of safety. They specify when mitigation alternatives need to be considered for interconnection, for example, at a substation, feeder, or PCC hosting capacity limit.

11.3 Grid Integration for Network-Connected DER

Requirements for grid integration for network-connected DER are specified in IEEE 1547-2018 clause 9 – DER on Distribution Secondary Grid/Area/Street (grid) Networks and Spot Networks.

IEEE 1547-2018 clause 9.1 addresses several specific issues related to DER integration into networks.

11.3.1 Area Networks

Requirements for area networks are specified in IEEE 1547-2018 clause 9.2 – Distribution Secondary Grid Networks.

Area networks, such as in downtown locations, are typically 120/208V and are served by multiple transformer banks and meshed on secondaries. In area networks DERs must be limited to avoid reverse power that causes network protectors to open. In addition, the DER must not cause network protector cycling.

DER systems less than or equal to {typically 25 to 150 kW} can be approved if the DER maximum generation is {typically, ≤5% - 10%} of the area network peak load. {UTILITY} has the right to revise the maximum export level in case of changed conditions or future negative impacts.

Customer-owned export limiting controls may be required to prevent any inadvertent operation of network protectors.

In some cases, customers can export excess generation to the network if export can be accomplished without causing reverse power to any of the network protectors at any time. In some cases, customers will be required to maintain a minimum import limit.

11.3.2 Spot Networks

Requirements for spot networks are specified in IEEE 1547-2018 clause 9.3 – Distribution Secondary Spot Networks.

DER can be approved on spot networks if aggregate DER generation is {typically, ≤5% - 10%} of the spot network peak load. Export of generation into the spot network transformer(s) for any duration will not be allowed. {UTILITY} maintains the right to revise operating limits in case of changed conditions or future negative impacts.

The facility must maintain a minimum power import of at least {typically, 5-20%} of the facility minimum. If the DER is PV, facility minimum includes minimum daytime load. {UTILITY} will have the right to revise the allowed injection level in case of future negative impact.

Customer-owned export limiting controls may be required to prevent any inadvertent operation of network protectors.

11.3.3 Special Review and Evaluation of Network Protection

Witness testing for network-connected DER includes a {UTILITY} System Protection/Telecom point-to-point testing of any protection scheme. This test is in addition to any other commissioning and witness testing required in Section 13 – "Commissioning and Verification Requirements" of this document.

11.3.4 Special Control Requirements for Network Service

Telemetry is required for all DERs larger than 150 kW and installed with network service. Requirements are to monitor three-phase voltage, three-phase power, three-phase current, total MW, total MVAR, the power crossing at the interchange of the facility, and any solar output. Remote trip capability may also be required. The monitored values shall be brought back into an Energy Management System (EMS), DMS, DERMS, or other management system and stored into a {UTILITY} database. Interoperability requirements described in chapter 10 apply.

11.4 Control Requirements for Export Limiting

The use of one of the methods listed below is allowed to limit the export of electrical power across the Point of Interconnection. The export capacity of the DER shall be this limit which does not include any inadvertent export for planning purposes and will be included as a limitation in the interconnection agreement.

When proposing to limit or prevent export from the DER facility with one of the approved methods, {UTILITY} will need to review the methods and the operation of the control device. The following information will be required from the applicant at the time of submission.

- Manufacturer and model of the device or power control system, or the components that make up the system.

- The technical specifications of the devices or power control systems.
- A description of the operating modes, services, and any specific settings that are enabled, and how the hardware/software present in the design is used to accomplish the goals of the mode being used.

11.4.1 Non-Exporting DER

- **Reverse Power Protection (Device 32R):** To limit export of power across the point of interconnection, a reverse power protective function is implemented using a utility grade protective relay. The default setting for this protective function is {typically, 0.1%} (export) of the service transformer's nominal base nameplate power rating, with a maximum {typically, 2-30} second time delay to limit inadvertent export.
- **Minimum Power Protection (Device 32F):** To limit export of power across the point of interconnection, a minimum import protective function is implemented utilizing a utility grade protective relay. The default setting for this protective function is {typically, 5%} (import) of the small generator facility's total nameplate rating, with a maximum {typically, 2-30} second time delay to limit inadvertent export.
- **Relative distributed energy resource rating:** This option requires the small generator facility's nameplate rating to be so small in comparison to its host facility's minimum load that the use of additional protective functions is not required to ensure that power will not be exported to the electric distribution system. This option requires the small generator facility's nameplate rating to be no greater than {typically, 50%} of the interconnection customer's verifiable minimum host load during relevant hours over the past 12 months. This option may not be available for interconnections to area networks or spot networks.

11.4.2 Limited Export DER

- **Directional Power Protection (Device 32):** To limit export of power across the point of interconnection, a directional power protective function is implemented using a utility grade protective relay. The default setting for this protective function is to be the export capacity value, with a maximum {Typically, 2-30} second time delay to limit inadvertent export.
- **Configured Power Rating:** A reduced output power rating utilizing the power rating configuration setting may be used to ensure the small generator facility does not generate power beyond a certain value lower than the nameplate rating. The configuration setting corresponds to the active or apparent power ratings in Table 28 of IEEE 1547-2018, as described in subclause 10.4. A local small generator facility communication interface is not required to utilize the configuration setting if it can be set by other means. The reduced power rating may be indicated by means of a nameplate rating replacement, a supplemental adhesive nameplate rating tag to indicate the reduced nameplate rating, or a signed attestation from the customer confirming the reduced capacity.

11.4.3 Limited Export or Non-Exporting DER

- **Certified Power Control Systems:** A small generator facility may use certified power control systems to limit export. Small generator facility utilizing this option must use a power control system and inverter certified per UL 1741 by a nationally recognized testing laboratory (NRTL) with a maximum open loop response time of no more than 30 seconds to limit inadvertent export. NRTL testing to the UL Power Control System Certification Requirement Decision must be accepted until similar test procedures for power control systems are included in a standard. This option may not be available for interconnections to area networks or spot networks as the open loop response time may be too long to prevent network protectors from operating.

- **Agreed-upon Means:** A small generator facility may be designed with other control systems and/or protective functions to limit export and inadvertent export if mutual agreement is reached with {UTILITY}. The limits may be based on technical limitations of the interconnection customer's equipment or the electric distribution system equipment. To ensure inadvertent export remains within mutually agreed-upon limits, the interconnection customer may use an uncertified power control system, an internal transfer relay, energy management system, or other customer facility hardware or software if approved by {UTILITY}.

EPRI Note: *Setting power elements in a protective relay will result in a several percentage range of error when accounting for relay element, as well as CT and PT error. This needs to be considered when reviewing settings.*

12 FACILITY REVENUE METERING

12.1 Revenue Metering

The Applicant is responsible for all costs associated with the metering and data acquisition equipment as outlined in this chapter. {UTILITY} and the applicant must have unrestricted access 24 hours a day, 7 days a week, to metering and data acquisition equipment. The meter must either be located within 10’ of the disconnect or permanent instructions must be posted indicating the disconnect switch’s location.

All revenue metering equipment must comply with the AHJ for revenue meeting (e.g., the state public service commission), as well as technical requirements for the location provided by {UTILITY}.

12.1.1 Metering at Low Voltage Interconnection

The metering specifications for secondary metering will follow {UTILITY specification} and can be found at {location of utility specific reference}.

Where Net Metering is implemented, non-bi-directional meters may need to be upgraded with revenue metering capable of accurately recording two-way power flows.

12.1.2 Metering at Medium Voltage Interconnection

The metering specifications for medium voltage primary metering will follow {UTILITY specification} and can be found at {location of utility specific reference}.

EPRI Note: *The basic configuration of revenue metering consists of a bi-directional revenue grade meter (import and export) at each PCC with the utility system. Additional separate revenue metering for the gross output of the generation may be required, depending on the generation capacity, applicable contractual provisions, and associated tariffs.*

In cases where DER is required to be separately metered or sub-metered, utility-specific requirements for meter base may need to be provided such as electrical service standards, enclosure listing, applicable clearances, and physical conformance.

In cases where DER participate in wholesale services, separate revenue meter or sub-metering may be required according to the ISO/RTO. Telemetry may also be required. Refer to applicable ISO/RTO requirements.

A
REFERENCE STANDARDS AND GUIDELINES

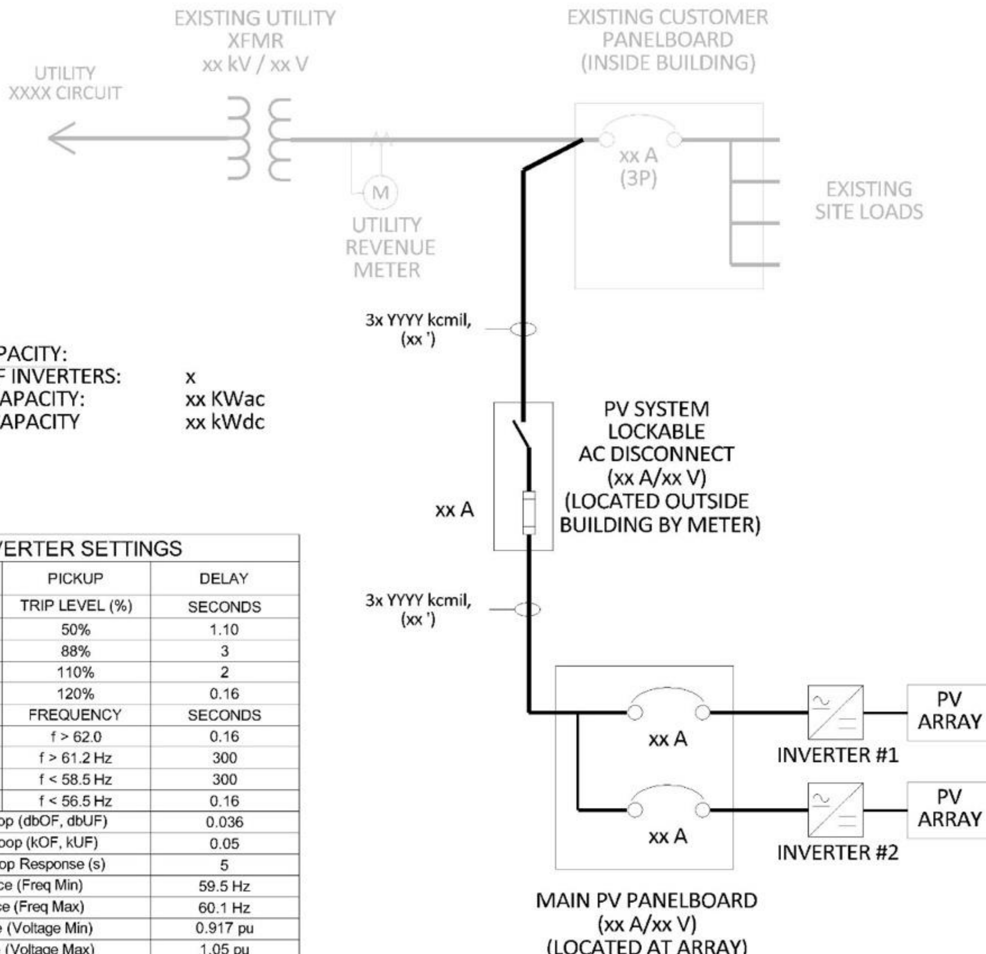
Table A-1
Reference Standards and Guidelines

Standard/Guideline	Title	Year
IEEE 1547	IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems	2018
IEEE 1547.1	IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems	2020
IEEE 1547.2	IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems	2023
IEEE 519	IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems	2022
IEEE 1453	IEEE Recommended Practice for the Analysis of Fluctuating Installations on Power Systems	2022
ANSI C84.1	American National Standard for Electric Power Systems and Equipment—Voltage Ratings (60 Hertz)	2020
ANSI C62.92	IEEE Guide for the Application of Neutral Grounding in Electrical Utility Systems	Various
UL 1741	Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources	2021
UL 1741 SB	Supplement B to UL 1741 for Smart Inverters	2021
UL 1741 CRD for PCS	Certification Requirement Decision for Power Control Systems	Various
UL 1741 CRD for Multimode	Certification Requirement Decision for Multimode Inverters	Various

B
TYPICAL ONE-LINE DIAGRAMS

The following One-Line Diagrams are intended to be typical or representative samples of various types and sizes of generation facilities that are connected to and operate in parallel with the {UTILITY} power delivery system and do not purport to cover every possible case. Each site will have to be specifically designed considering the unique characteristics of each installation, the specific location of the PCC, and the operating and contractual requirements for that site. Additional ISO/RTO and NERC requirements may also apply.

Table B-1
Sample One-Line Diagram – Small System



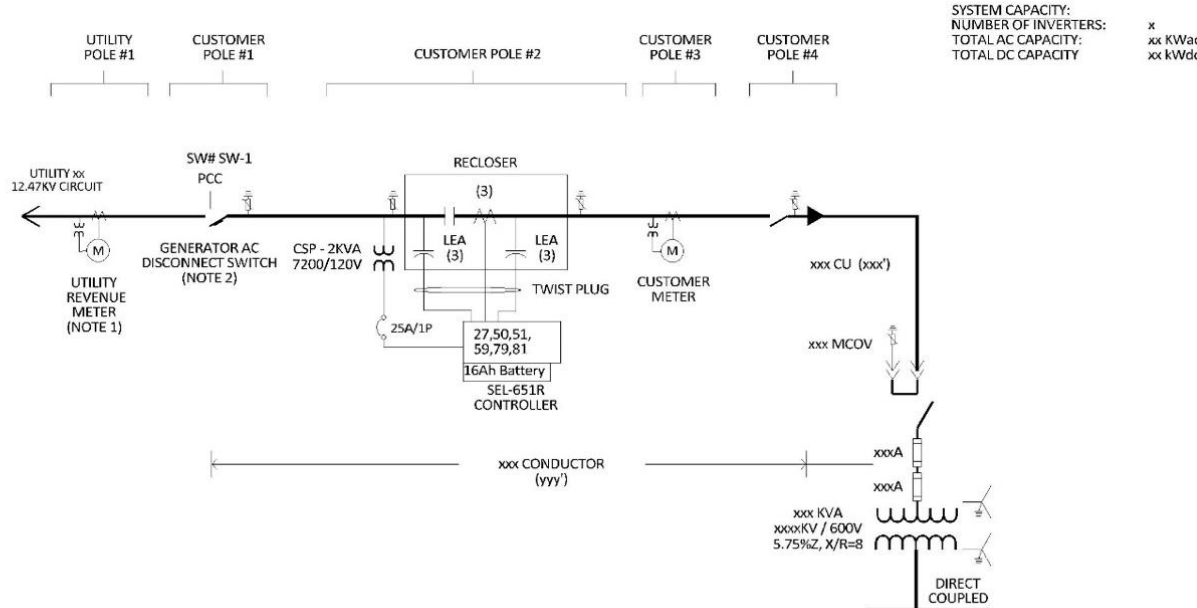
SYSTEM CAPACITY:
NUMBER OF INVERTERS: x
TOTAL AC CAPACITY: xx KWac
TOTAL DC CAPACITY xx kWdc

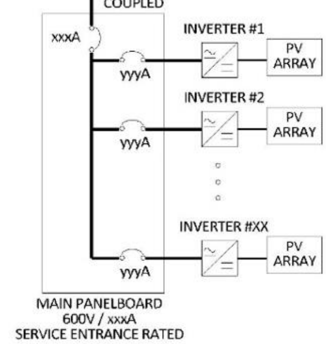
INVERTER SETTINGS		
ANSI	PICKUP	DELAY
	TRIP LEVEL (%)	SECONDS
27	50%	1.10
27	88%	3
59	110%	2
59	120%	0.16
	FREQUENCY	SECONDS
81O	f > 62.0	0.16
81O	f > 61.2 Hz	300
81U	f < 58.5 Hz	300
81U	f < 56.5 Hz	0.16
Frequency Droop (dbOF, dbUF)		0.036
Frequency Droop (kOF, kUF)		0.05
Frequency Droop Response (s)		5
Enter Service (Freq Min)		59.5 Hz
Enter Service (Freq Max)		60.1 Hz
Enter Service (Voltage Min)		0.917 pu
Enter Service (Voltage Max)		1.05 pu
Enter Service - Delay Before Export		300 sec
Enter Service- Ramp Time		300 sec
Enter Service- Ramp Characteristics		Linear
Reactive Power Function		Volt-VAR
Modify Volt-VAR Curve from Defaults		Yes
Enable Volt-Watt		No
Modify Volt-Watt Curve from Default		Yes

PV MODULES	
PANEL MANUFACTURER	XXXXXXX
PANEL MODEL	XXXXXXX
PANEL QUANTITY	XXXXXXX
PANEL RATING	xx W

INVERTERS								
INVERTER #	MANUFACTURER	MODEL	KW	KVA	AC VOLTS	DC VOLTS	AMPS	CONDUCTOR
1	XXX	XXXX	XXX	XXXX	XXX	XXXX	XXX	XXXXX
2	XXX	XXXX	XXX	XXXX	XXX	XXXX	XXX	XXXXX

Table B-2
Sample One-Line Diagram – Primary Metered System





PROTECTIVE RELAY SETTINGS					
ANSI	PICKUP			TOTAL CLEARING TIME / TIME DIAL / TCC	
	VNON(In) = 30.7V,			CYCLES	SECONDS
	LEA PT RATIO: 8793:1, PTR=234.5, CT=300:1				
	TRIP LEVEL (%)	PRIMARY	SECONDARY		
27	50%	3.6kV	15.35V	66	1.1
27	88%	6.34kV	27.04V	120	2
59	110%	7.92kV	33.77V	120	2
59	120%	8.64kV	36.84V	9.6	0.16
50	N/A	xxxA	x.xA	INST	
51		xxxA	x.xA	0.5TD, U4 CURVE	
59N	50%	3.6kV	15.35V	60	1
	FREQUENCY			CYCLES	SECONDS
81O	f > 62.0			9.6	0.16
81O	f > 61.2 Hz			18000	300
81U	f < 58.8 Hz			18000	300
81U	f < 57.0 Hz			9.6	0.16
79	5 MINUTE RECLOSING AFTER VOLTAGE TRIP ONCE VOLTAGE WITHIN 5% OF NOMINAL AND FREQUENCY BETWEEN 59.5 AND 60.5 HZ, EXCEPT FOR OVERCURRENT TRIPS				

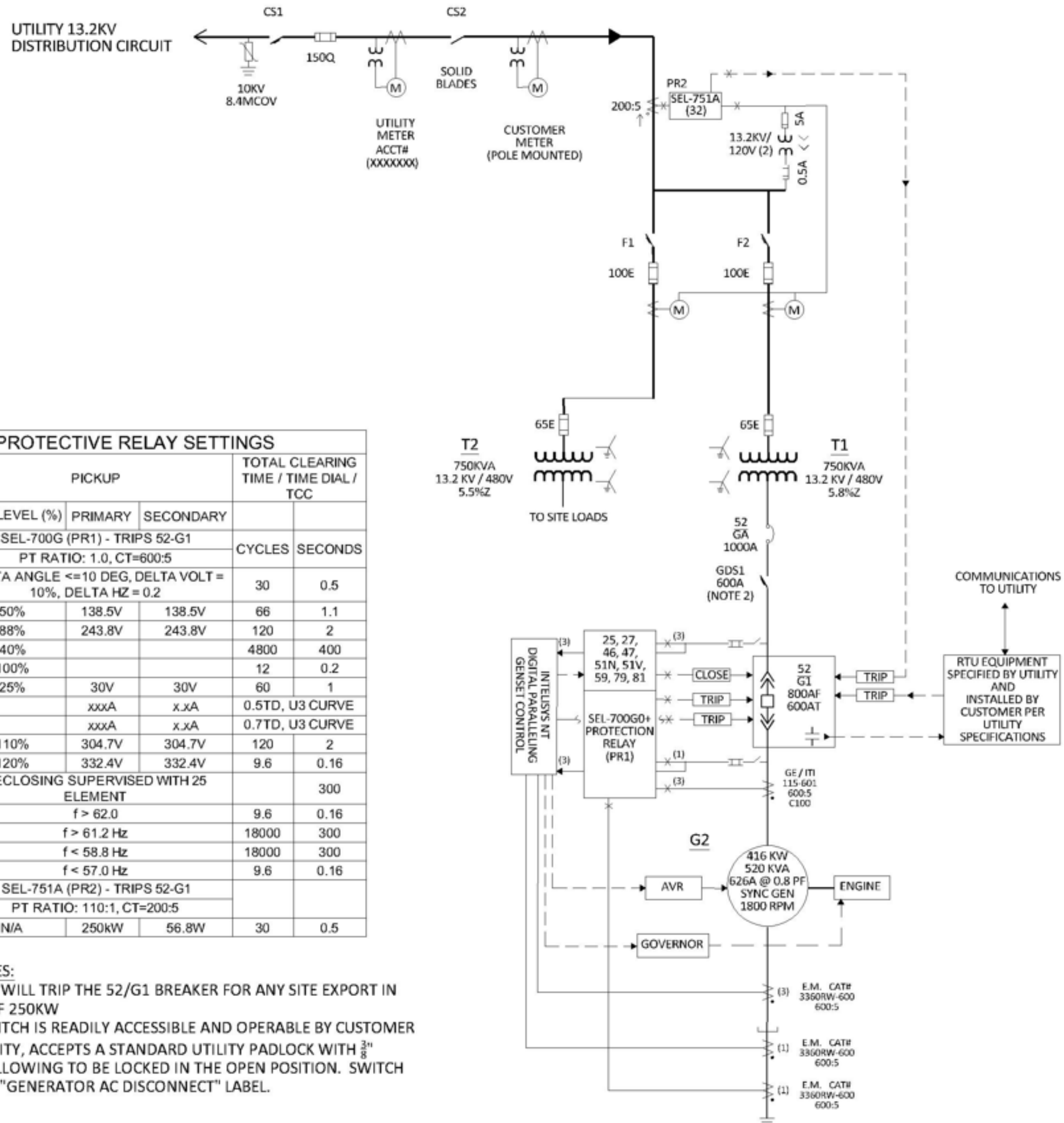
INVERTER SETTINGS		
ANSI	PICKUP	DELAY
	TRIP LEVEL (%)	SECONDS
27	50%	1.10
27	88%	3
59	110%	2
59	120%	0.16
	FREQUENCY	SECONDS
81O	f > 62.0	0.16
81O	f > 61.2 Hz	300
81U	f < 58.5 Hz	300
81U	f < 56.5 Hz	0.16
Frequency Droop (dbOF, dbUF)		0.036
Frequency Droop (kOF, kUF)		0.05
Frequency Droop Response (s)		5
Enter Service (Freq Min)		59.5 Hz
Enter Service (Freq Max)		60.1 Hz
Enter Service (Voltage Min)		0.917 pu
Enter Service (Voltage Max)		1.05 pu
Enter Service - Delay Before Export		300 sec
Enter Service- Ramp Time		300 sec
Enter Service- Ramp Characteristics		Linear
Reactive Power Function		Volt-VAR
Modify Volt-VAR Curve from Defaults		Yes
Enable Volt-Watt		No
Modify Volt-Watt Curve from Default		Yes

PV MODULES	
PANEL MANUFACTURER	XXXXXXX
PANEL MODEL	XXXXXXX
PANEL QUANTITY	XXXXXXX
PANEL RATING	xx W

INVERTERS							
QUANTITY	MANUFACTURER	MODEL	KW	KVA	AC VOLTS	AMPS	CONDUCTOR
x	XXX	XXXX	XXX	XXXX	XXX	XXX	XXXXX

DRAWING NOTES:
1. CUSTOMER TO PROVIDE POLE AND METERING PAN FOR REVENUE METER. UTILITY TO PROVIDE CTS/PTS/ AND METER.
2. LOCKABLE SWITCH SIGNAGE TO INCLUDE "PHOTOVOLTAIC SYSTEM AC DISCONNECT SWITCH" AND SHALL BE INSTALLED AT A READILY ACCESSIBLE LOCATION. UTILITY TO BE PROVIDED 24-HOUR/7-DAY UNLIMITED ACCESS AND CONTROL OF THIS ISOLATION SWITCH.

Table B-3
Sample One-Line Diagram – Synchronous Machine System with Export Limit



PROTECTIVE RELAY SETTINGS					
ANSI	PICKUP			TOTAL CLEARING TIME / TIME DIAL / TCC	
	TRIP LEVEL (%)	PRIMARY	SECONDARY		
	SEL-700G (PR1) - TRIPS 52-G1 PT RATIO: 1.0, CT=600:5			CYCLES	SECONDS
25	DELTA ANGLE <=10 DEG, DELTA VOLT = 10%, DELTA HZ = 0.2			30	0.5
27	50%	138.5V	138.5V	66	1.1
27	88%	243.8V	243.8V	120	2
46-1	40%			4800	400
46-2	100%			12	0.2
47	25%	30V	30V	60	1
51N		xxxA	x.xA	0.5TD, U3 CURVE	
51V		xxxA	x.xA	0.7TD, U3 CURVE	
59	110%	304.7V	304.7V	120	2
59	120%	332.4V	332.4V	9.6	0.16
79	RECLOSING SUPERVISED WITH 25 ELEMENT				300
81O	f > 62.0			9.6	0.16
81O	f > 61.2 Hz			18000	300
81U	f < 58.8 Hz			18000	300
81U	f < 57.0 Hz			9.6	0.16
	SEL-751A (PR2) - TRIPS 52-G1 PT RATIO: 110:1, CT=200:5				
32	N/A	250kW	56.8W	30	0.5

DRAWING NOTES:

1. SEL-751A WILL TRIP THE 52/G1 BREAKER FOR ANY SITE EXPORT IN EXCESS OF 250KW
2. GDS1 SWITCH IS READILY ACCESSIBLE AND OPERABLE BY CUSTOMER AND UTILITY, ACCEPTS A STANDARD UTILITY PADLOCK WITH $\frac{3}{8}$" SHANK ALLOWING TO BE LOCKED IN THE OPEN POSITION. SWITCH TO HAVE "GENERATOR AC DISCONNECT" LABEL.

C
TYPICAL LAYOUTS

Table C-1
Sample Layout – Small System

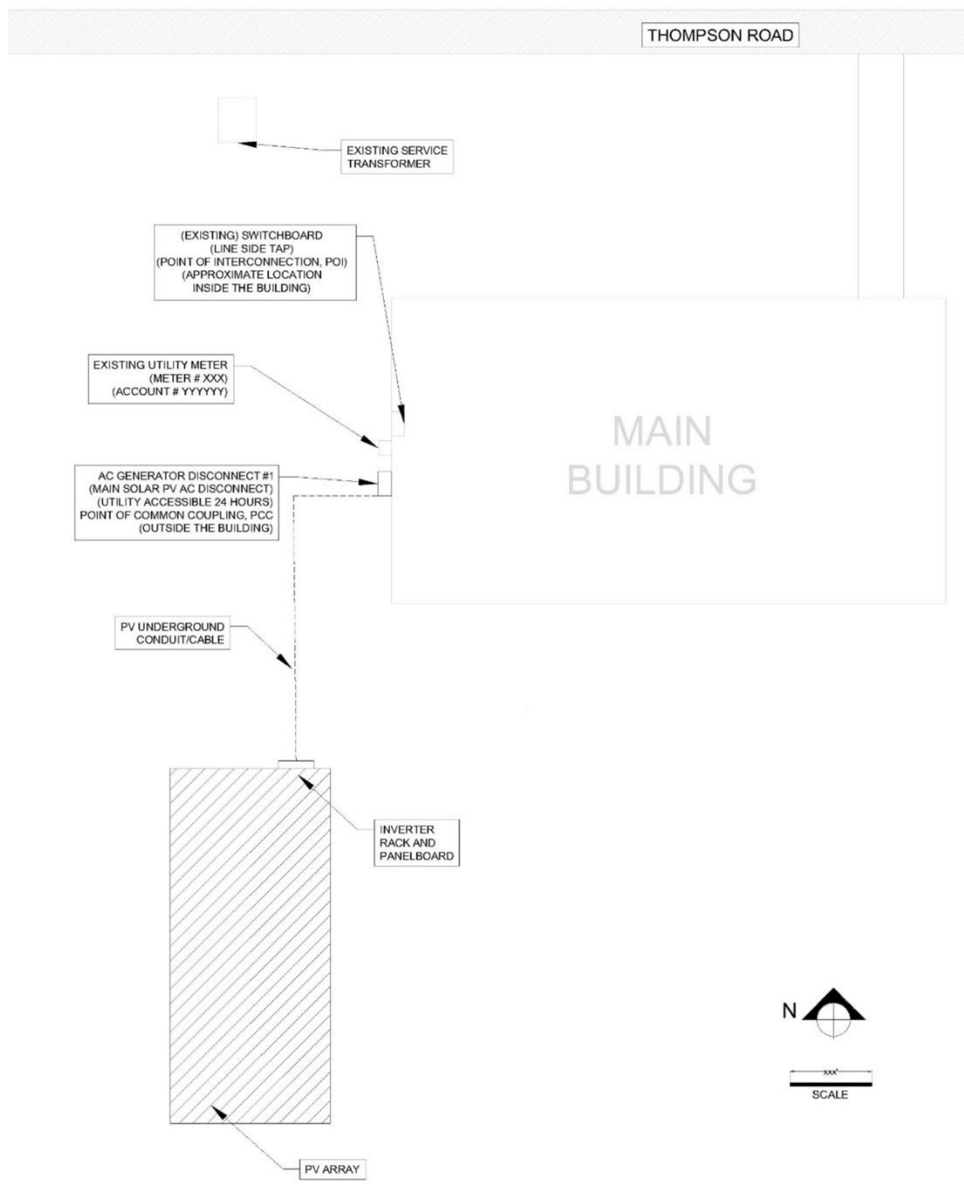
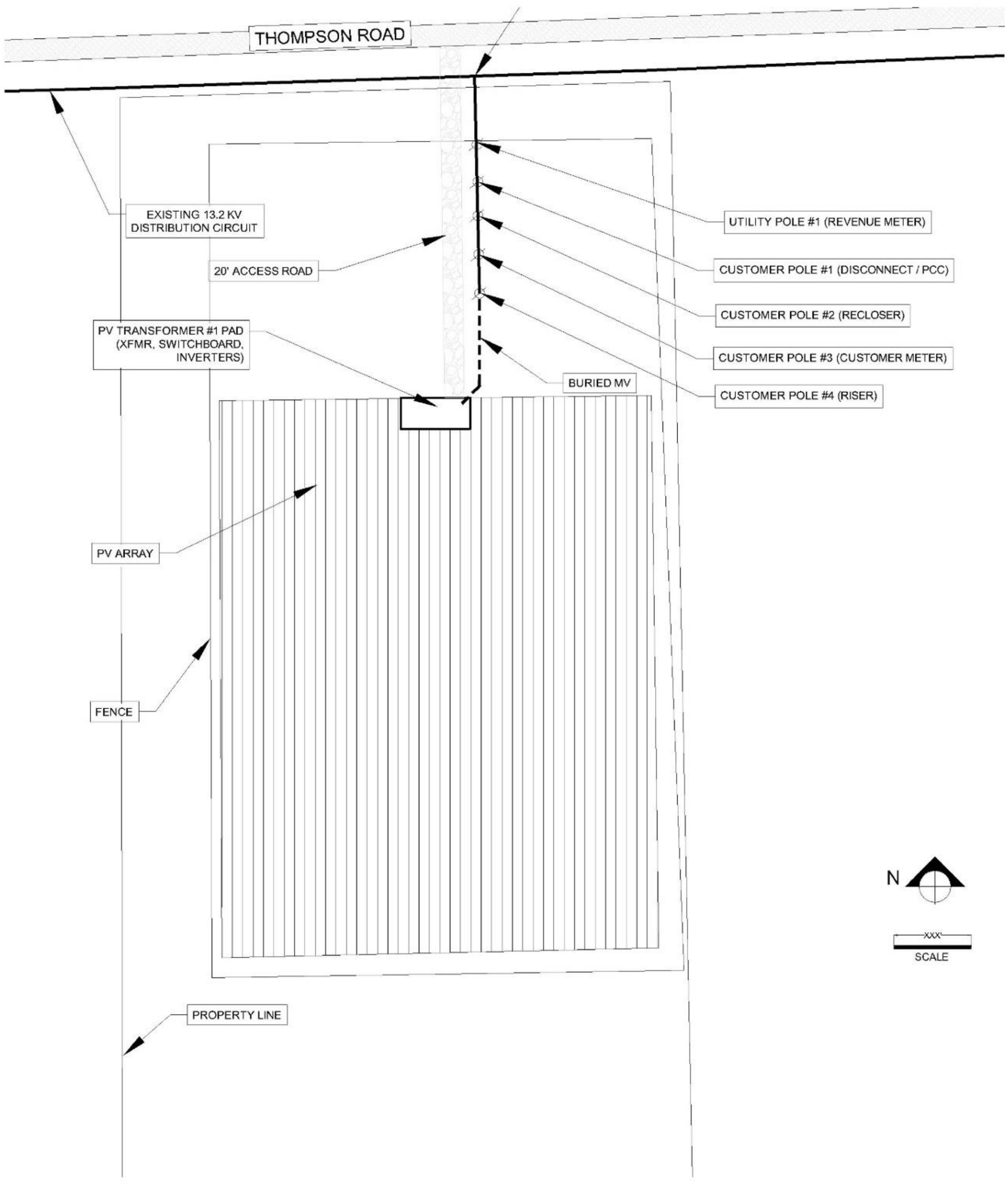


Table C-2
Sample Layout – Primary Metered System



D

GENERAL PROTECTION REQUIREMENTS

The table provided is a sample showing different possible categories of interconnections and the requirements for Area EPS protection of the DER unit. This is a template that would be updated by the utility for their requirements. The categories will need to be adjusted for the utility and tariffs that are available for interconnection. The behind the meter column is a good example of where a utility may split into two separate groups based on size of the installation and if remote monitoring/control is required. The table is not meant to indicate protection elements required for the protection of the generator, but for the system.

Table D-1
Sample Interconnection Categories and Associated Requirements

	Single-phase, UL1741SB, BTM	3-Phase, UL1741SB, BTM	3-Phase, UL1741SB, <500kW, LV RPA	3-Phase, UL1741SB, <500kW, MV RPA	3-Phase, UL1741SB, >500kW, MV RPA	3-Phase, Grid Forming IBR, MV RPA	3-Phase, Rotating Machine, MV RPA	Comments
Frequency/Voltage Certified Protection	X	X	X	X	X	X	X	
Frequency/Voltage Backup Protection		X			X	X	X	
Single-Phase Open Protection		X		X	X	X	X	
GFOV Contribution Assessment		X		X	X	X	X	
Ground Overcurrent (51N)				X	X	X	X	Only if supplemental ground source
Voltage Controlled Overcurrent (51V)							X	Difficulty in coordinating with undervoltage ride-through and expected current with variable generation
Ground Overvoltage (59N)				X	X	X	X	Beneficial on 3 wire systems and for ground fault detection on EPS system
Sync Check/Dead Line (25/27L)						X	X	
Utility 89L Control					X	X	X	
Remote Metering					X	X	X	

E

SMALL SITE COMMISSIONING PLAN TEMPLATE

Site Address: ___________________________

Account Number: ______________________

Commissioning Date: _________________

		(Y/N)
1	Verify Construction Per Design:	
	Inverter Quantity/Sizes	
	Inverter Make/Model	
	Disconnect Location and Labelling	
	Optional - Inverter Settings	
	Optional - Documentation of Inverter Serial #s	
2	Verify Islanding Protection	
	Confirm Inverter kW Output	
	Open Main Disconnect	
	Verify Inverters Stop	
3	Verify Reconnect Time	
	Close Disconnect, Record Time:	
	Time of Inverter kW Output:	
	Optional - Verify Ramp Rate, 100% Output	

Notes:

Witnessed by:

Utility: _____________________ Installer/Owner: ____________________

F

LARGE SITE COMMISSIONING PLAN TEMPLATE

Site Address: ____________________________

Account Number: ______________________

Commissioning Date: _________________

		(Y/N)
1	Review of Pre Commissioning Information	
	Contractor As Built Drawings	
	Contractor Relay Testing Documentation	
	Contractor As Left Relay Settings	
2	Verify Construction Per Design:	
	Inverter Manufacturer/Model	
	Inverter Quantity/Sizes	
	Disconnect Location and Labelling	
	Optional - Inverter Settings	
	Optional - Documentation of Inverter Serial #s	
3	Confirm Relay Operation	
	Per Attachment 1	
4	Optional - Confirm SCADA	
	Per Attachment 2	
5	Verify Islanding Protection	
	Confirm Inverter kW Output	
	Optional LROV - Record kW Output at Open	
	Open Main Disconnect	
	Optional LROV - Record Max kV	
	Verify Inverters Stop	

6 Verify Reconnect Time

Close Disconnect, Record Time:	
Time of Inverter +kW Output:	
Optional - Verify Ramp Rate, 100% Output	

7 Optional – Single-Phase Open Testing

Phase A Open, Inverter Stop	
Phase B Open, Inverter Stop	
Phase C Open, Inverter Stop	

Notes:

Witnessed by:

Utility: ______________________ Installer/Owner: _____________________

Large Site Commissioning Plan Template Attachment 1

On Site Relaying Test Plan Template

1. PERFORM THE FOLLOWING RELAY TESTING (ALL PHASES) USING DOBLE TEST SET.

A. UNDERFREQUENCY TRIP (56.5HZ IN 0.11 SEC)
B. RECLOSING INITIATED (NOT LOCKOUT)
C. UNDERFREQUENCY TRIP (58.5HZ IN 300 SEC)
D. RECLOSING INITIATED (NOT LOCKOUT)
E. OVERFREQUENCY TRIP (61.5HZ IN 300 SEC)
F. RECLOSING INITIATED (NOT LOCKOUT)
G. OVERFREQUENCY TRIP (62HZ IN 0.11 SEC)
H. RECLOSING INITIATED (NOT LOCKOUT)

	Ph A	Ph B	Ph C
E. UNDERVOLTAGE #1 (50%) IN 1.0 SEC			
F. RECLOSING INITIATED (NOT LOCKOUT)			
G. UNDERVOLTAGE #2 (88%) IN 2.0 SEC			
H. RECLOSING INITIATED (NOT LOCKOUT)			
I. OVERVOLTAGE #1 (110%) IN 1.0 SEC			
J. RECLOSING INITIATED (NOT LOCKOUT)			
K. OVERVOLTAGE #2 (120%) IN 0.16 SEC			
L. RECLOSING INITIATED (NOT LOCKOUT)			
M. GROUND OVERVOLTAGE (3.7V IN 0.5 SEC) (OPTIONAL)			
N. RECLOSING INITIATED (NOT LOCKOUT) (OPTIONAL)			
O. PHASE TIME OVERCURRENT (0.1A, U4 CURVE, 1.0 TD)			
P. BREAKER LOCKOUT			
Q. DISCONNECT BATTERY, RECLOSER WILL TRIP			

2. VERIFICATION OF RELAY AND RECLOSER OPERATION

A. PROVIDE POWER TO RELAYS TO SIMULATE 3-PHASE UTILITY SOURCE
B. OPEN TEST SWITCH (AC PHASE A POTENTIAL). RECLOSER WILL TRIP.
C. ATTEMPT TO CLOSE RECLOSER VIA PUSHBUTTON, RECLOSER DOES NOT WITHIN 5 MINUTES
D. CLOSE TEST SWITCH (AC PHASE A POTENTIAL). RECLOSER WILL CLOSE AFTER 5 MINUTES.

Large Site Commissioning Plan Template Attachment 2

Monitoring Verification Template

1. MONITORING VERIFICATION (Verification of Customer Values vs. Utility Values)

	Customer		Utility		Match
	Mag	Angle	Mag	Angle	Y/N
IA					
IB					
IC					
VA					
VB					
VC					

	Customer	Utility	Match
KW			
KVAR			

2

2. RTU Testing (Verification to Utility SCADA System)

A. CONFIRM FOLLOWING ANALOG VALUES

	Customer	Utility	Match
IA			
IB			
IC			
VA			
VB			
VC			
KW			
KVAR			

B. OPTIONAL – CONFIRM BREAKER STATUS

BREAKER STATUS CHANGE

C. OPTIONAL – CONFIRM BREAKER CONTROL

BREAKER CONTROL

G
DER SETTINGS TABLES

The tables below respectively show the setting configuration for DERs under Cat-B and Cat-III normal and abnormal performance categories. Each table includes the standard label used in the EPRI Common File Format[13]. Utility-required settings should be adjusted if they deviate from Category B, Category III Default. Adjustable ranges are provided in General Technical Requirements, DER Support of Grid Voltage, and DER Response to Abnormal Conditions. Refer to IEEE 1547-2018 or EPRI Common File Format for Category A, Category I, and Category II parameter ranges.

Table G-1
DER Setting Configuration under Category B

ENTER SERVICE CRITERIA		**EPRI Common File Format**	**UNITS**	**Utility-Required Settings**
Permit Service		ES_PERMIT_SERVICE-SS	Mode	Enabled
Enter Service Voltage	ES Voltage Low Setting	ES_V_LOW-SS	V p.u.	0.917
	ES Voltage High Setting	ES_V_HIGH-SS	V p.u.	1.05
Enter Service Frequency	ES Frequency Low Setting	ES_F_LOW-SS	Hz	59.5
	ES Frequency High Setting	ES_F_HIGH-SS	Hz	60.1
Soft-Start Ramp	ES Randomized Delay	ES_RANDOMIZED_DELAY-SS	s	300
	ES Delay Setting	ES_DELAY-SS	s	300
	ES Ramp Rate Setting	ES_RAMP_RATE-SS	s	300
DER SUPPORT OF GRID VOLTAGE[14]		**EPRI Common File Format**	**UNITS**	**Utility-Required Setting**
Constant Power Factor Mode		CONST_PF_MODE_ENABLE-SS	Mode	Enabled

[13] EPRI has published the *Common File Format for Distributed Energy Resources Settings Exchange and Storage*, a document developed in collaboration with industry stakeholders (manufacturers, nationally recognized testing laboratories, certification entities, planning and operations engineers, etc.) that facilitates the DER settings file exchange. More details at https://www.epri.com/research/products/000000003002020201 (open to public).

[14] Constant Power Factor Mode is enabled in this example as a commonly implemented *default* mode, this simplified table includes the parameters associated with Constant Power Factor Mode (shown in grey below) and lists other DER Support of Grid Voltage modes as disabled.

Constant Power Factor Excitation	CONST_PF_EXCITATION-SS	Mode	INJ
Constant Power Factor setting	CONST_PF-SS	PF	1.00
Voltage-Reactive Power Mode	QV_MODE_ENABLE-SS	Mode	Disabled
Active Power Reactive Power Mode	QP_MODE_ENABLE-SS	Mode	Disabled
Constant Reactive Power Mode Enable	CONST_Q_MODE_ENABLE-SS	Mode	Disabled
Voltage-Active Power Mode Enable	PV_MODE_ENABLE-SS	Mode	Disabled

Table G-2
DER Setting Configuration under Category III

Mandatory Voltage Tripping Characteristics		EPRI Common File Format	UNITS	Utility Required Settings
OV2	HV Trip Curve Point OV2 Setting	OV2_TRIP_V-SS	V p.u.	1.20
	HV Trip Curve Point OV2 Setting	OV2_TRIP_T-SS	s	0.16
OV1	HV Trip Curve Point OV1 Setting	OV1_TRIP_V-SS	V p.u.	1.10
	HV Trip Curve Point OV1 Setting	OV1_TRIP_T-SS	s	13.00
UV1	LV Curve Trip Point UV1 Setting	UV1_TRIP_V-SS	V p.u.	0.88
	LV Curve Trip Point UV1 Setting	UV1_TRIP_T-SS	s	21.00
UV2	LV Curve Trip Point UV2 Setting	UV2_TRIP_V-SS	V p.u.	0.50
	LV Curve Trip Point UV2 Setting	UV2_TRIP_T-SS	s	2.00
MANDATORY FREQUENCY TRIPPING CHARACTERISTICS		**EPRI Common File Format**	**UNITS**	**Utility Required Settings**
OF2	OF Curve Trip Point OF2 Setting	OF2_TRIP_F-SS	Hz	62.00
	OF Curve Trip Point OF2 Setting	OF2_TRIP_T-SS	s	0.16
OF1	OF Curve Trip Point OF1 Setting	OF1_TRIP_F-SS	Hz	61.20
	OF Curve Trip Point OF1 Setting	OF1_TRIP_T-SS	s	300.00
UF1	UF Curve Trip Point UF1 Setting	UF1_TRIP_F-SS	Hz	58.50
	UF Curve Trip Point UF1 Setting	UF1_TRIP_T-SS	s	300.00

UF2	UF Curve Trip Point UF2 Setting	UF2_TRIP_F-SS	Hz	56.50
	UF Curve Trip Point UF2 Setting	UF2_TRIP_T-SS	s	0.16

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