DER Technical Interconnection and Interoperability Requirements (TIIR) for the AEP System

Effective Date: 2/1/2024

Revision: 0.3

Description: DER requirements for interconnection to the AEP System

Note: To request a prior version of the TIIR document send a note to AEPDERTIIR@aep.com

Revision History

Rev.	Description of Change(s)	By	Date
0	Original Issue	DIR Distribution Planning & Analysis	8/25/2023
0.1	Minor corrections/clarifications before external publication. Includes changes to Operating Company approval of meter collars for DER installations in 12.3, and a note about the effective date for interconnections in Ohio.	AEP	11/15/2023
0.2	Correct Figure 4 and Replace Figures 6 and 9	AEP	12/28/2023
0.3	Updated Thermal Impact Limits in Section 9.3 and performed other minor updates and corrections.	AEP	1/29/2024

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1.0 Introduction

1.1 Scope and Applicability

This DER Technical Interconnection and Interoperability Requirements (TIIR) document specifies the technical requirements for the interconnection of Distributed Energy Resources (DERs) to AEP's system in several DER interconnection scenarios as shown in Table 1 below. In some scenarios, other Transmission or RTO requirements may apply in addition to the requirements specified in this document. All applicable requirements will be reviewed with interconnecting customers during the interconnection process.

Table 1: DER Interconnection Scenarios

DER Interconnection Scenario	Only the Requirements in This Document (TIIR) Apply	The Requirements in This Document (TIIR) AND Transmission/ RTO Requirements Apply	The AEP Transmission Interconnection Requirements AND RTO Requirements Apply
The DER is interconnecting to the traditional, affiliate AEP distribution system, these distribution facilities do not operate under FERC jurisdiction, and the DER does not intend to participate in any RTO market	Yes	No	No
The DER is interconnecting to the traditional, affiliate AEP distribution system facility and these distribution facilities do not operate under FERC jurisdiction, but the DER is large enough to qualify for RTO oversight or the DER intends to participate in an RTO market	No	Yes	No
The DER is interconnecting to non-integrated Transmission facilities, that are specifically assigned and/or excluded from general Open Access Transmission Tariff (OATT) rates, and that operate below 60 kV	No	Yes	No
The DER is interconnecting to non-integrated Transmission facilities, that are specifically assigned and/or excluded from general OATT rates, and that operate at or above 60 kV	No	No	Yes

DER Interconnection Scenario	Only the Requirements in This Document (TIIR) Apply	The Requirements in This Document (TIIR) AND Transmission/ RTO Requirements Apply	The AEP Transmission Interconnection Requirements AND RTO Requirements Apply
The DER is interconnecting to integrated Transmission facilities, that are included in the general OATT rates, and that operate at or above 60 kV & above (or involve some specific 34.5 kV facilities in the PJM region-that are included in OATT rates)	No	No	Yes

The AEP Distribution System includes AC nominal voltages at or below 34.5 kV (see Table 2 for applicable voltage ranges by jurisdiction). The purpose for these requirements is to maintain the safety, reliability, and quality of service of the AEP Distribution System, and to protect AEP and Customer assets. These requirements apply to all DER interconnections. Limited exceptions may be made solely at AEP's discretion and only in writing by an authorized staff member after appropriate inspection, technical review, and approval.

While the Federal Energy Regulatory Commission (FERC) and other relevant industry bodies have broad definitions for DER, this TIIR applies only to the asset types defined as DER within Section 2.0 of this document. All DER referred to in this document connected to AEP's distribution system and certain non-integrated transmission facilities as described in the table above are required to have an interconnection service agreement with AEP (these may be described as "DER interconnections" in this document).

AEP does not require a DER interconnection for an electric vehicle (EV) that operates solely as a load, or in other words, an EV that is unidirectional (known as V1G) and thus, can only charge and could never discharge to the grid or any onsite loads.

Backup power systems that are designed and tested to verify that they only operate when the premise is not connected to the AEP Area EPS are not required to complete the DER Interconnection Service Request process or have an interconnection service agreement with AEP.

This document references standards external to the TIIR (sources include, but are not limited to ANSI, IEC, IEEE, and UL), all of which are incorporated as AEP requirements. The TIIR may include summary statements related to external industry standards. However, if there is a conflict between the summary statements and the full text of the external standards, the external standards shall prevail when referenced.

Finally, the reader should be aware that for reading simplicity, the terms "the TIIR" and "technical requirements" have been used interchangeably within this document to reference the full scope of requirements in this DER TIIR.

1.2 Adoption of IEEE Std 1547™-2018

AEP intends to adopt *IEEE Std 1547™-2018*[1], as corrected by *IEEE Std 1547™-2018*[2] errata and as amended by *IEEE Std 1547a™-2020*[3], (hereafter: *IEEE Std 1547™-2018*) for all DER interconnected to its distribution system. All DER interconnecting under these technical requirements shall meet requirements as specified in *IEEE Std 1547™-2018* and be tested, verified, or certified according to applicable standards.

AEP's additional requirements for DER interconnections that are beyond the scope of *IEEE Std 1547™-2018* are also included in this document.

AEP's adoption of *IEEE Std 1547™-2018* is in alignment with the Feb 12, 2020, resolution from the National Association of Regulatory Utility Commissioners (NARUC) titled "Resolution Recommending State Commissions Act to Adopt and Implement Distributed Energy Resource Standard *IEEE 1547-2018"*[4].

In all circumstances, AEP identifies the Reference Point of Applicability (RPA) as being at the Point of Common Coupling (PCC), as defined by *IEEE Std. 1547™-2018.*

To obtain the authoritative requirements from IEEE 1547, and the contextualization of individual requirements or clauses relative to the entire standard document, readers are encouraged to access the complete IEEE 1547 document previously referenced. To acquire the *IEEE 1547™-2018* standard, go to: https://www.techstreet.com/ieee/searches/38059541.

1.3 Effective Date, Grandfathering Clause, and Material Modification

The requirements specified in this document shall apply to all DER interconnection request applications received on or after January 1, 2024. Effective then, for DER applications submitted to AEP, inverters shall be UL 1741 SB, or equivalent standards, certified as "Grid Support Interactive Inverter" or "Grid Support Utility Interactive Inverter", and installed or commissioned with the *IEEE Std 1547™-2018* specified performance capabilities.

Note: The effective date for applications in the state of Ohio is still to be determined, pending certain regulatory decisions.

Any DER interconnections that are either already in operation or within the application submission process prior to January 1, 2024, are deemed "grandfathered" in by AEP and may continue to meet the interconnection requirements in effect at the time of the application prior to this date. Existing DER interconnections that have undergone or in the process of making a *material modification* after

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
4 https://pubs.naruc.org/pub/E86EF74B-155D-0A36-3138-B1A08D20E52B

the effective date must comply with the requirements specified in this document, as determined by AEP.

In this document, a “material modification” means a change to the equipment settings, DER configuration, or the interconnection site of the DER facility that can materially impact the cost, timing, or design of any customer interconnection facilities or upgrades, or adversely impact other interdependent interconnection requests. This can occur while an interconnection application is in the process of being reviewed or approved, after approval before the DER is commissioned, or anytime during the life of the DER after the DER facility has been placed in-service. For the state of Virginia, "Material modification" has the meaning ascribed to it in 20VAC5-314-39. For DER applicants in other states connecting to the AEP system, a modification is considered “material” if it creates a condition or change that:

- Creates an adverse impact to the operation, safety, or reliability of AEP’s distribution system or an affected system
- Affects any equipment electrically located between the point of common coupling and the DER that directly impacts the performance of the DER
- Requires the replacement of generating equipment, such as generator-type, inverters, transformers, relaying, or controls, that is not a like-for-like substitution in size, ratings, impedances, efficiencies, or capabilities of the equipment specified in the original or preceding interconnection request
- Results in noncertified devices (see Section 1.4.1)
- Modifies previously approved transformer connections or grounding
- Alters certified inverters (see Section 4.1) with different specifications or different inverter control specifications, equipment settings or DER configurations previously approved
- Disrupts the protection relay or automation controller settings that affect the operational characteristics of the DER Facility
- Increases or reduces the maximum nameplate capacity of the DER facility
- Amends the location of the DER site
- Requires the removal or retirement of any DER equipment

Customers shall communicate proposed DER changes to AEP for review. It is at AEP’s sole discretion to determine if any modification constitutes a *material modification* for purposes of the TIIR. Customers who make any modifications without participating in an AEP *material modification* review will be considered in breach of the Customer’s interconnection agreement and will remain as such until AEP determines a review has been properly performed, changes approved, and the resulting updated or new interconnection agreement is executed between the Customer and AEP.

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, including *IEEE Std 1547™-2018.* Other applicable standards may include, but are not limited to, the National Electrical Code, North American Electric Reliability Corporation rules (applicable for independent system operators and regional transmission organizations), and all applicable laws, statutes, guidelines, and regulations including any imposed by the independent system operators or regional transmission organizations that pertain to distribution-connected or non-integrated transmission-connected DERs. Customer responsibilities include installing, setting, and maintaining all protective devices necessary for safe grid integration and to protect the Customer's and AEP's facilities as defined in the interconnection agreement.

This TIIR document does not remove the Customer's responsibility for reading, understanding, and complying with all content of *IEEE Std 1547™-2018* and *IEEE Std 1547.1™-2020*, as well as all applicable local codes, standards, statutes, and commission orders.

1.4.2 Utility Managed and Operated Distribution System

Requirements specified in this TIIR document are also intended to complement AEP's efforts and responsibility to maintain distribution system safety, power quality, and reliability. Continuity and quality of service for all customers are key responsibilities of AEP.

1.4.3 Requirements Related to Ongoing Utility Upgrades

Coordination between AEP and the Customer is necessary, as AEP's system is constantly changing. At times, changes in AEP's system may necessitate updates to protection and control, or other parameters at a DER facility. AEP reserves the right to work with the Customer to analyze DER facilities and coordinate the implementation of solutions in these situations. Any changes in requirements will be communicated to the Customer in writing and reflected in the Interconnection Service Agreement as needed. AEP requires the Customer to take responsibility for implementing changes in accordance with the Interconnection Service Agreement.

2.0 Definitions and Acronyms

Terminology used in this document and its usage is intended to follow that of IEEE, IEC, and ANSI standards. In some cases, terms related to the FERC-SGIP and NFPA related codes such as the US National Electric Code, NFPA-70 are used. Definitions in the following table will assist with the understanding of the TIIR and its contents.

Term	Acronym	Definition
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.
American Electric Power	AEP	American Electric Power (AEP) – A major investor-owned electric utility in the United States composed of several operating companies, several transmission companies, and member to several joint ventures. For purposes of this document, AEP refers to the AEP distribution operating companies that maintain the AEP Distribution System and associated assets: AEP Ohio, AEP Texas, Appalachian Power, Indiana Michigan Power, Kentucky Power, Kingsport Power, Public Service Company of Oklahoma, Southwestern Electric Power Company, and Wheeling Power.
AEP Distribution System		AEP's operating companies maintain more than 220,000 miles of distribution power lines in 11 states. References in this document to the distribution system include distribution lines operated at AC nominal voltages at or below 34.5 kV and maintained by any of the following AEP operating companies: AEP Ohio, AEP Texas, Appalachian Power, Indiana Michigan Power, Kentucky Power, Kingsport Power, Public Service Company of Oklahoma, Southwestern Electric Power Company, and Wheeling Power.
Area Electric Power System	Area EPS	An Electric Power System (EPS) that serves a Local EPS (Reference *TIIR* Appendix B and *IEEE Std 1547™-2018 Figure 2*).
Area Electric Power System Operator	Area EPS Operator	AEP is the Area EPS Operator and is responsible for designing, building, operating, and maintaining the Area EPS (Reference *IEEE Std 1547™-2018* Clause 3.1).
AEP Facility		The AEP-owned equipment on AEP's side of the Point of Common Coupling, AEP-owned metering equipment, and all other AEP equipment identified in the interconnection agreement.
Applicant		The entity applying for a new or materially modified interconnection.

Term	Acronym	Definition
Capacity		The ability of the electric system (or part of the system) to transmit power demand for a particular time interval without exceeding accepted design specifications.
Control Center		The AEP office that monitors and has direct control over the operation of AEP's power delivery system.
Customer		Any adult person, partnership, association, corporation, or other entity interacting with AEP who: • Receives delivery service • Supplies electric service • Combines electric supply and delivery service A Customer is responsible for any DER requiring a connection to the AEP electrical system.
DER Facility		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.
DER Unit		An individual DER device inside a group of DERs that collectively form a system.
Direct Transfer Trip	DTT	Direct Transfer Trip (DTT) protection is a method of sending a trip signal from one location to another. Various communication systems including, but not limited to, phone lines, spread-spectrum radio, licensed radio, microwave, and fiber optics can provide the signal path. If DTT is installed, the scheme shall be negotiated between AEP and the DER owner.
Distributed Energy Resource	DER	A source of electric power that is not directly connected to the bulk power system. A Distributed Energy Resource (DER) includes both generators and energy storage facilities operating in parallel to the distribution system and capable of exporting active power to an EPS. An interconnection system or a supplemental DER device that is necessary for compliance with *IEEE Std 1547™-2018* is part of a DER.
Distribution Automation	DA	Automation of real-time functions in AEP's operation of the distribution power system, including fault location, isolation, and service restoration.
Distribution System		The interconnected arrangement of lines, transformers, generators, or other devices used to deliver or control the delivery of energy that make up the electric power system. In this document, distribution system refers to the medium and low voltage portions of the system.
Electric Power Research Institute	EPRI	The Electric Power Research Institute, Inc. (epri.com) is an independent, nonprofit organization that conducts research

Term	Acronym	Definition
		and development relating to the generation, delivery and use of electricity for the benefit of the public.
Electric Power System	EPS	Facilities that deliver electric power to a load and may include generation units (Reference *IEEE Std 1547™-2018 Figure 2*).
Flicker Emission Levels		The level of a given rapid output fluctuation from a particular DER device, equipment, system, or disturbing installation as a whole, assessed and measured in a specified manner (IEEE 1453 and IEC 61000-4-15).
Grid		The interconnected arrangement of lines, transformers, and generators that make up the electric power system.
Inadvertent Export		Any unscheduled export of active power from a DER, exceeding a specified magnitude and for a limited duration, due to fluctuations in load-following behavior.
Integration Margin		Limits defined and used to protect the grid by providing a safety margin added to DER integration limits (e.g., limits to prevent reverse power on a substation power transformer).
Intentional Island		An intentionally planned electrical island that is capable of being energized by one or more Local EPSs. The intentional island has load, one or more DERs, and the ability to both disconnect from and parallel with the Area EPS.
Interconnection Agreement(s)		A contract between AEP and one or more parties that outlines and governs the interconnection requirements of a generation facility.
Interconnection Equipment		Equipment deemed necessary to safely interconnect the DER Facility to AEP’s power delivery system, including all relaying, interrupting devices, metering or communication equipment needed to protect the DER Facility and AEP’s power delivery system and to control and safely operate the DER Facility in parallel with AEP’s power delivery system. (Adapted from *IEEE Std 1547™-2018)*
Island		A condition in which a portion of an Area EPS is energized solely by one or more Local EPSs while that portion of the Area EPS is electrically separated from the rest of the Area EPS on all phases to which the DER is connected.
Local DER Communication Interface		A local interface capable of communicating in support of the information exchange requirements specified in this standard for all applicable functions that are supported in the DER (*IEEE Std 1547™-2018*).

Term	Acronym	Definition
Local Electric Power System	Local EPS	An EPS contained entirely within a single premise or group of premises (Reference *TIIR* Appendix B and *IEEE Std 1547™-2018 Figure 2*).
Material Modification		A change to the equipment settings, equipment configuration, or interconnection site of the DER facility that has a material impact on the cost, timing, or design of any customer interconnection facilities or upgrades, or that may adversely impact other interdependent interconnection requests. Material Modification is further defined in Section 1.3.
Nameplate Capacity		The sum total of maximum rated power output of all of a DER's constituent generating units and/or energy storage as identified on the manufacturer nameplate, regardless of whether its production/export is going to be limited by any approved means.
Nameplate Rating		The normal maximum operating rating applied to a piece of electrical equipment. This can include kW, kVA, Volts, Amps, or any other specific item specification for the equipment.
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.
Operating Profile		The manner in which the distributed energy resource 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 Interconnection and the resource characteristics, e.g., solar output profile or Energy Storage System operation.
Parallel Operation		Any electrical connection between AEP's power delivery system and the Customer's generation source.
Plant Controller		A single point of interface that provides visibility into the DER operations of the whole site.
Point of Common Coupling	PCC	The point of connection between the Area EPS and the Local EPS, equivalent, in most cases, to "service point" as specified in the National Electric Code® (NEC®) and the National Electric Safety Code® (NESC®) (Reference *TIIR* Appendix B and *IEEE Std 1547™-2018 Figure 2*).
Point of Common Coupling Meter	PCC Meter	The traditional revenue meter that measures the energy delivered to the Customer and any excess generation from the Customer DER facility back to the Area EPS.

Term	Acronym	Definition
Point of Connection	PoC	Also known as point of DER connection, the point where a DER unit is electrically connected to a Local EPS and meets the requirements of *IEEE Std 1547™-2018* exclusive of any load present in the respective part of the Local EPS (Reference *TIIR* Appendix B and *IEEE Std 1547™-2018 Figure 2*).
Point of Connection Meter	PoC Meter	The PoC Meter, sometimes also referred to as a Production Meter, measures the output of the Customer's DER facility. This meter is also programmed to register and record usage in each direction.
Power Control System		A device or system that has the capability to modify and/or control the electrical characteristics and performance of a DER Unit connected to the Area EPS.
Production Meter		The Production Meter is programmed to register and record the input and output of the Customer's DER facility and is commonly referred to as the PoC Meter.
Qualified Party/ Personnel		Possesses skills and knowledge related to the construction and operation of the electrical equipment and installations and has received safety training to recognize and avoid the hazards involved. (NEC 2017)
Reference Point of Applicability	RPA	AEP identifies the reference point of applicability (RPA) as being at the point of common coupling (PCC) as defined by *IEEE Std 1547™-2018*. DER requirements of this TIIR apply to the RPA located at the PCC in all circumstances.
Regional Reliability Coordinator		The functional entity that maintains the real-time operating reliability of the bulk electric power within a reliability coordinator area.
Remote Terminal Unit	RTU	The remote unit of a supervisory control system used to telemeter operating data, provide device status/alarms and to provide remote control of equipment at a substation or generator site. The unit communicates with a master unit at AEP's Control Center.
Revenue Metering		For purposes of this document, revenue metering shall refer to the meter or meters used for billing purposes and the instrument transformers, communications equipment, and wiring between these devices.
Service Transformer		A service transformer (distribution transformer) is a transformer that provides the final voltage transformation in the electric power distribution system, stepping down the voltage used in the distribution lines to the level used by the Customer.

Term	Acronym	Definition
Study Track		Within the Technical Review Key Process Step of the DER Interconnection Process with AEP, projects are evaluated according to technology type and Operating Profile, location, and size or complexity of the proposed DER. Projects whose screening outcomes result in System Impact and or Facility Studies needed are said to be on the Study Track.
Supervisory Control and Data Acquisition	SCADA	A tool used by dispatchers to monitor system conditions, as well as perform limited remote substation functions such as opening/closing a breaker.
Supplemental DER Device		Any Customer-owned equipment that is used to obtain compliance with some or all of the requirements of this TIIR (Reference *TIIR* Appendix B and *IEEE Std 1547™-2018 Figure 2).*
System Emergency		An imminent or occurring condition on AEP's power delivery system, the ISO/RTO System, the system of a neighboring utility, or in the DER 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.
Technical Interconnection and Interoperability Requirements	TIIR	A document that describes the "DER Technical Interconnection and Interoperability Requirements (TIIR) for the AEP System."
Telemetry		The process by which measurable data from remote devices is collected and transmitted to a control center, and by which operating commands from a control center are transmitted to the remote devices. In the case of DERs, applications include telemetry for protection device status, power flows, settings, or other facility/related AEP equipment condition status(es).
Unintentional Island		An unplanned island created without the approval of AEP that usually follows the loss of a portion of the Area EPS.

3.0 Interconnection Application Process

AEP's interconnection application process is conveyed at a high level summary in Figure 1 and further described in Sections 3.1 through 3.3 of this document.

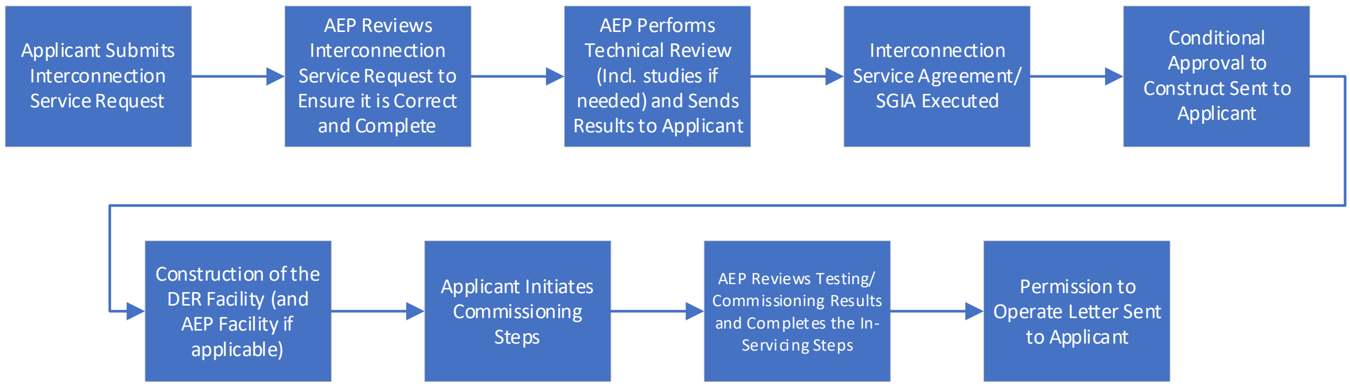


Figure 1: Interconnection Application Process Flow

3.1 Application Process Overview

All DER interconnection requests shall be submitted via AEP's online DER interconnection application system prior to the Applicant initiating construction on the DER facility. This requirement allows the Area EPS team to review whether the intended system design can be interconnected as desired. This helps to minimize potentially time-consuming or costly rework. Requirements as to what the Applicant should submit in the DER one-line diagram during the application process are listed in Appendix C: Typical One-Line Diagrams.

Upon receipt of an application, AEP reviews the provided information to ensure the application is properly completed. Once the application is considered acceptable, AEP will perform a technical review that begins with a screening analysis and may also require specialized studies including a system impact study. For applications entering the Study Track, additional engagement with the Applicant is required.

Details of the interconnection process, as well as the technical review, are dependent upon multiple factors including, but not limited to the state/local requirements, the DER's size, location of the PCC, system complexity, and planned Operating Profile. As such, the Applicant shall provide AEP with the DER Operating Profile related to the following conditions: normal operation for all planned modes of operation; momentary loss of voltage or frequency; extended loss of voltage or frequency; partial loss of Customer-owned equipment; and any other abnormal condition.

The primary technical features under review include voltage regulation, protection, power quality, and thermal limits. Other areas for review include electrical service requirements and metering, telemetry, and at higher power levels, bulk system stability and reactive power balance studies. The technical review may include one or more levels of analysis depending on the nature of the project.

Applicants may reference their state commission's site to see current rules specific to the location of their project. In some cases, analytical tools and feeder data are required to complete the review or study. Areas with high relative penetration of DER are more likely to require additional review and detailed studies.

3.2 Technical Review Outcomes and Approvals

The expected outcome upon completion of an application's technical review is for AEP to provide written results outlining any special conditions and/or mitigation requirements as well as the site-specific connection requirements, along with the estimated costs. Study Track applications are furnished with a written Study Report detailing the impacts that must be mitigated for the interconnection of the DER Facility and its intended Operating Profile, as described in the application, modeled, and reviewed.

The technical review leads to any of four different outcomes that are the basis of conditions to which the Applicant must approve for the interconnection application to move forward. These are:

- Agreed upon changes in the proposed DER system design
- Changes in DER operation, such as limited operating modes and including AEP control and/or curtailment of the DER under certain contingency circumstances
- Area EPS enhancement(s) to resolve issues identified in the technical review
- No changes resulting in an *as-is* approval of the proposed DER requirements

In all cases certain interconnection equipment will be needed, such as the visible lockable disconnect switch (see Section 4.9). This interconnection equipment will be described along with the technical review interconnection conditions described above. If the Applicant agrees to the conditions prescribed in the technical review, AEP will offer an interconnection agreement to be signed by the Applicant. This contract includes details of the relevant conditions described and approved by the Applicant. Upon execution of the interconnection agreement by the Applicant and AEP, the Applicant may begin construction of the DER facility. If Area EPS construction is required, AEP typically initiates its design and construction project at this point. AEP's commencement of the Area EPS construction is conditioned upon the Applicant meeting all contractual obligations identified in the application process and interconnection agreement.

Note: In Virginia, DER Applications for projects not eligible for the Net Metering Tariff, and those 500 kW or larger, will be completed using the Small Generator Interconnection Agreement (SGIA) rather than the standard Interconnection Services Agreement (ISA). The SGIA has additional requirements that must be met, including evidence of agreement for purchase of the electricity produced by the generator.

Upon the completion of Applicant and/or AEP construction, the Applicant must complete the required commissioning steps (see Section 13.0) and receive a written *Permission to Operate* notice from AEP prior to beginning operation. AEP reserves the right to review and/or test the DER at the time of installation or any point in the life of the DER facility.

3.3 General Criteria for DER Interconnection

All DER interconnections will be evaluated for conformance with applicable state tariff requirements and the technical requirements referenced or contained in this document. In areas where there may be additional state or local requirements beyond this TIIR document, the Customer and their developer will need to make sure those requirements are also met.

Additionally, all DER interconnections will be evaluated and shall not:

- Compromise the safety of the public or personnel
- Degrade service to any customers
- Compromise the security or reliability of AEP's electrical systems

Further, developers, owners, and operators of approved DER interconnections are subject to all authorities having jurisdiction over the DER interconnection and are required to comply with AEP's:

- Direction and instructions during defined emergency conditions
- Requests to remove the DER from service when AEP is performing line maintenance or other work on the circuit or substation to which the DER is connected.

4.0 General Technical Requirements

The DER interconnection shall comply with *IEEE Std 1547™-2018* and *IEEE Std 1547.1™-2020*. Inverters shall be UL 1741 SB certified as "Grid Support Interactive Inverter" or "Grid Support Utility Interactive Inverter" and installed or commissioned with the *IEEE Std 1547™-2018* specified performance capabilities. See Section 1.4.1 of this document.

In addition, the Customer is responsible for compliance with other codes that include: The National Electrical Code, Local Safety Codes, North American Electric Reliability Corporation rules (applicable for independent system operators), and all applicable laws, statutes, guidelines, regulations, and codes. This includes installing, setting, and maintaining all protective devices necessary for safe grid integration and protection of the Customer's facilities.

The Customer must be aware of how the installation of other equipment at their facility with the DER may impact the ability of the DER itself to meet *IEEE Std 1547™-2018* requirements, particularly those related to open-phase detection at the RPA.

4.1 Applicable Voltages

Per IEEE Std 1547™-2018 Clause 4.3, the *applicable voltages* determine the performance of a Local EPS or DER and are the electrical quantities specified with regard to the reference point of applicability, individual phase-to-neutral, phase-to-ground, or phase-to-phase combination and time resolution.

The range of nominal Area EPS voltages present across the AEP system (overhead or underground) are defined in Table 2 below.

Table 2: Applicable Area EPS Voltages Across the AEP System

	AEP Ohio	**AEP Texas**	**Appalachian Power Company**	**Kentucky Power Company**	**Indiana Michigan Power Company***	**Public Service Company of Oklahoma**	**Southwestern Electric Power Company**
Medium Voltage (kV, phase-phase)	4.16 to 34.50	4.16 to 24.90	4.16 to 34.50	2.40 to 34.50	4.16 to 34.50	2.40 to 34.50	4.16 to 34.50
Low Voltage (V, phase-phase)	208 (network systems), 240 to 480						

* For purposes of the state of Michigan's interconnection rules, the low voltage range covers all voltages up to 25 kV, and the high voltage range covers all voltages at or above 25 kV.

4.2 Dedicated Feeder Requirement

AEP is evaluating requirements for dedicated feeders to interconnect certain types and sizes of DERs.

4.3 Transformer Configuration Requirements

This section defines the requirements for allowable service transformer winding configurations to interface DER to the four-wire grounded-wye Distribution System Primary Area EPS across the AEP system, pending the results of an appropriate screen or study executed as part of the AEP DER interconnection process.

Use of an approved configuration does not automatically approve a DER for parallel operation with AEP facilities nor does it relieve the DER Owner (Customer) of the obligation to follow the AEP DER interconnection process. An additional evaluation will be required if more transformers are installed in the Customer’s facility between the DER equipment and the PCC.

AEP has established these requirements to:

- Ensure a proposed DER system interconnection with AEP’s distribution facilities maintains system ground integrity
- Minimize abnormal transient overvoltage amplitude during system or DER events

All other transformer winding configurations not explicitly marked as “Acceptable” in this document are deemed unacceptable to interface DER to the Area EPS.

AEP does not endorse a particular DER and interconnection system design, nor does it assure fitness of the design to accomplish intended functions.

4.3.1 Service and Interconnection Transformers

For purposes of this requirement, AEP defines Service Transformer and Interconnection Transformer as follows:

- **Service Transformer** – A transformer installed to provide electrical connection for one or more customers to the AEP Distribution System. The high-side of the service transformer connects to the AEP Distribution System Primary, and the low-side connects to one or more customer sites. This equipment may be AEP-owned or customer-owned.
- **Interconnection Transformer** – A customer-owned transformer installed to provide electrical connection for the Customer’s equipment. This transformer can be a customer-owned service transformer, connecting the AEP Distribution System Primary to the customer-owned equipment, or an additional transformer installed between the AEP-owned service transformer and the customer-owned equipment.

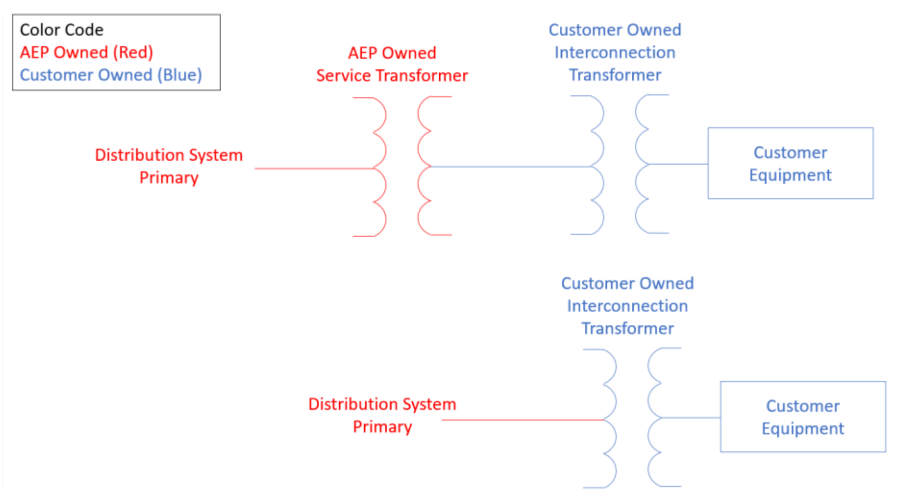


Figure 2: Service Transformer and Interconnection Transformer Examples

4.3.2 Acceptable Three-Phase Transformer Winding Configurations

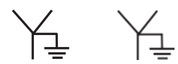
The following three-phase transformer-winding configurations, shown in Table 3 and Table 4 below, may be acceptable for the service transformer or customer-owned transformer connection between AEP's four-wire grounded-wye Distribution System (Primary) and a DER (Secondary), pending results of an appropriate screen or study.

All three-phase DER installations for DER greater than or equal to 250 kW shall have a distribution primary ground source configuration that cannot be separated from the DER while the DER is providing capacity to the distribution system primary equipment facilities.

Table 3: Transformer Connections and Zero Sequence Current Acceptable Options Regardless of Generator/Inverter Configuration

Winding Configuration	Transformation Primary (Pri.) ◄ Secondary (Sec.) ►
Grounded Wye/Delta	
Grounded Wye/ Grounded Wye with a Delta Tertiary	

Table 4: Transformer Connections and Zero Sequence Current Acceptable Options only for Grounded Wye Generator/Inverter Configuration

Winding Configuration	Transformation Primary (Pri.) Secondary (Sec.)
Grounded Wye/ Grounded Wye	

4.3.3 Acceptable Single-Phase Transformer Windings for Single-Phase DER

The following single-phase transformer-winding configuration may be acceptable for the service transformer connection between AEP's four-wire grounded-wye Distribution System (Primary) and a DER (Secondary), pending results of an appropriate screen or study.

AEP accepts these DER single-phase service transformer winding configurations as shown in Figure 3 below, where the transformer is connected line to ground on the distribution primary (MV) bushings and either:

- grounded on the secondary (LV) bushings to the DER (preferred)
- ungrounded on the transformer secondary only when the customer side is grounded in accordance with NEC 2023 rule 250.4(B)(4) and that this is demonstrated in the provided electrical one-line diagram

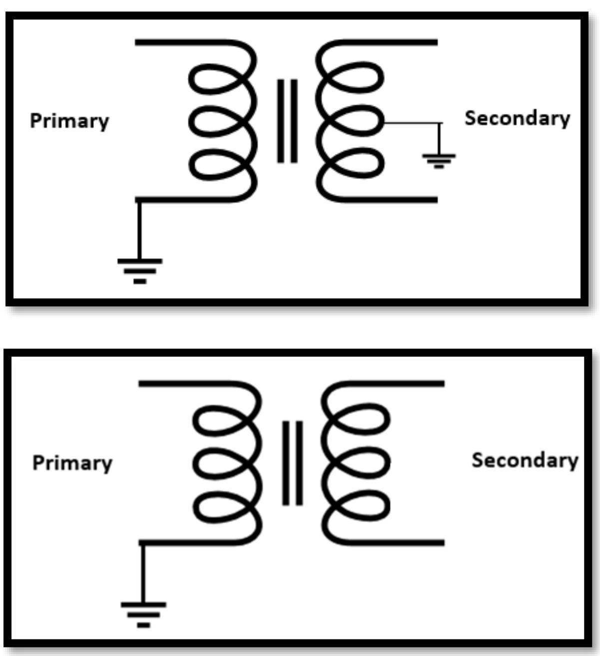


Figure 3: Acceptable Single-Phase Transformer Connections

4.3.4 Additional Transformer Winding Clarifications

In addition to the requirements previously described, AEP provides the following clarifications:

- The transformer winding connected to the distribution system primary shall match the grounding configuration of the distribution system primary
- DER may not be interconnected to the distribution system primary utilizing an autotransformer as the interconnection transformer. An autotransformer is a transformer that uses a common winding for both the primary and secondary windings.
- DER are not permitted to connect to an open-delta service transformer configuration, regardless of the DER being a single-phase or multi-phase system
- Three-phase DERs may only be connected to three-phase feeders

4.4 Effective Grounding Integration

In accordance with *IEEE Std 1547™-2018* Clause 4.12, the grounding scheme of the DER interconnection shall be coordinated with the ground fault protection of the Area EPS.

4.5 Open-Phase Detection

In accordance with *IEEE Std 1547™-2018* Clause 6.2.2, the DER shall detect and *cease to energize* and trip all phases to which the DER is connected for any open-phase condition occurring directly at the RPA and the applicable voltages. The DER shall *cease to energize* and trip within 2.0 seconds of the open-phase condition.

4.6 Cease to Energize

In accordance with *IEEE Std 1547™-2018* Clause 4.5, in the *cease to energize* state, the DER shall not deliver active power during steady-state or transient conditions. The requirements for *cease to energize* shall apply to the point of DER connection (PoC).

AEP may issue a *cease to energize* signal and command to connected DER. If the DER meets the requirement for *cease to energize* by disconnecting the local EPS, or the portion of the local EPS to which the DER is connected from the Area EPS, the DER may continue to deliver power to the portion of the Local EPS that is disconnected from the Area EPS. The requirements for *cease to energize* shall apply to the point of DER connection (PoC).

4.7 Control Capability Requirements

In accordance with *IEEE Std 1547™-2018* Clause 4.6, the DER shall be capable of responding to external inputs, including:

- Capability to disable permit service (*IEEE Std 1547™-2018* Clause 4.6.1)
- Capability to limit active power (*IEEE Std 1547™-2018* Clause 4.6.2)
- Execution of mode or parameter changes (*IEEE Std 1547™-2018* Clause 4.6.3)

AEP may curtail DER production during real time operations by leveraging these functions to address operational emergencies or constraints.

4.8 Prioritization of DER Responses

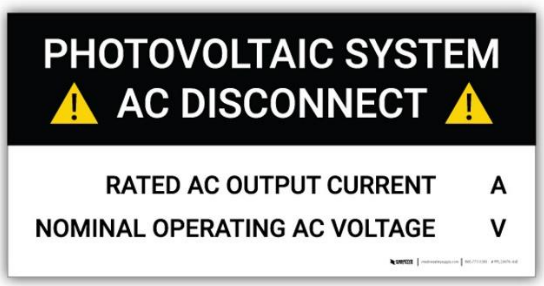
The response of DER Facilities connected to the Area EPS shall be in accordance with the prioritization defined in *IEEE Std 1547™-2018* Clause 4.7.

4.9 Manual Isolation Device Requirements

As permitted by *IEEE Std 1547™-2018* Clause 4.8, a readily accessible, lockable, visible-break isolation device shall be located between the Area EPS and the DER.

AEP will only allow a single isolation device between the Area EPS and all DER connecting to the Area EPS at a customer's premise. This single isolation device is required to allow the company to isolate all DER at the premise with a single operation. The company may require this isolation device to be properly fused for the size (ampacity) of the wires in a "line side tap" connection configuration.

This isolation device should be immediately adjacent to the AEP meter (within 6 feet and between 4 to 6 feet above grade) and be clearly marked with labeling that easily identify the DER Disconnect Switch which will isolate energized equipment from the utility grid, such as that shown in the inset below.



If the isolation device cannot be located as required, a permanent plaque must be placed next to the existing meter clearly stating the location of the isolation device at the premise.

AEP expects this isolation device to be properly maintained in good working condition by the interconnecting DER Customer. Where used for isolation of a DER unit that continues to produce voltage after isolation from the Area EPS, the isolation device shall be capable of withstanding 220% of the DER rated voltage across the device for an indefinite duration.

A knife-blade switch that conforms with the National Electric Code and has a visible break/open is an example of an appropriate isolation device for overhead installations. The Safety Disconnect Switch required by the 2020 National Electric Code may serve as an appropriate manual isolation device in some installations.

Note: A Safety Disconnect Switch (NEC 2020) may also be required in certain new installations. These requirements are in addition to those defined in Section 4.10.

4.10 Remote Controlled Isolation Device Requirements

AEP requires that any DER facility with a total nameplate capacity of 500 kW or larger that is not collocated with site load (i.e., a residential, a commercial or industrial customer), shall include an AEP-owned and controlled disconnect switch, furnished and installed by AEP, and to be located on the AEP side of the Point of Common Coupling (PCC) or a location approved by AEP. Where the DER facility interconnects to a circuit that is part of a local Distribution Automation (DA) scheme, the AEP-owned and controlled disconnect switch may be integrated into the DA scheme. The DER may be required to disconnect under alternate grid configurations.

For DER facilities that meet the size requirement stated above and where the DER facility is collocated with site load (i.e., a residential, a commercial or industrial customer), AEP and the Customer will jointly develop a plan to provide AEP with the capability to remotely disconnect the DER Facility.

4.11 Inadvertent Energization of Area EPS

As required in *IEEE Std 1547™-2018* Clause 4.9, the DER shall not energize the Area EPS when the Area EPS is de-energized.

Exceptions may be given for intentional Area EPS islands at the discretion of AEP. Only AEP-owned or -operated DER may serve facilities in the Area EPS in an intentional island.

4.12 Enter Service

Following the guidance set by *IEEE Std 1547™-2018* Clauses 4.10.2 and 4.10.3, AEP has selected the default Enter Service settings for all categories of DER connecting to the Area EPS as specified in Table 5 below.

Table 5: Enter Service Settings

ENTER SERVICE CRITERIA		Standard Parameter Root Label (based on 1547.1 and modified by Electric Power Research Institute (EPRI))	UNITS	Utility-Required Setting	Default, Valid, Invalid	IEEE Std 1547-2018 Category B		
						Default	Min	Max
Permit Service		ES_PERMIT_SERVICE-SS	Mode	Enabled	Default	Enabled	Enabled	Disabled
Enter Service Voltage	ES Voltage Low Setting	ES_V_LOW-SS	V p.u.	0.917	Default	0.917	0.88	0.95
	ES Voltage High Setting	ES_V_HIGH-SS	V p.u.	1.05	Default	1.05	1.05	1.06
Enter Service Frequency	ES Frequency Low Setting	ES_F_LOW-SS	Hz	59.5	Default	59.5	59.0	59.9
	ES Frequency High Setting	ES_F_HIGH-SS	Hz	60.1	Default	60.1	60.1	61.0
Soft-Start Ramp	ES Randomized Delay	ES_RANDOMIZED_DELAY-SS	s	300	Default	300	1	1000
	ES Delay Setting	ES_DELAY-SS	s	300	Default	300	0	600
	ES Ramp Rate Setting	ES_RAMP_RATE-SS	s	300	Default	300	1	1000

4.13 Synchronization

In accordance with *IEEE Std 1547™-2018* Clause 4.10.4, the DER shall parallel with the Area EPS without causing step changes in the root mean square (RMS) voltage at the PCC exceeding 3% of nominal when the PCC is at medium voltage or exceeding 5% of nominal when the PCC is at low voltage. DERs that produce fundamental voltage before connecting to the Area EPS shall not be synchronized outside of the tolerances specified in *Table 5* of the standard (shown as Table 6 below*)*.

Table 6: Synchronization Parameters Limits for Synchronous Interconnection to an EPS or an Energized Local EPS to an Energized Area EPS

Aggregate rating of DER units (kVA)	Frequency difference (Δf, Hz)	Voltage difference (ΔV, %)	Phase angle difference ($\Delta\Phi$, °)
0–500	0.3	10	20
> 500–1 500	0.2	5	15
> 1 500	0.1	3	10

4.14 DER Electromagnetic Interference (EMI) Withstand Capability

AEP reserves the right to request and review or approve documentation from the Customer related to the EMI withstand capabilities of the connected DER or DER components. AEP may request that the connected DER or DER components be compliant with *IEEE Std C37.90.2™*, *IEC 61000-4-3*, or other applicable industry standards.

5.0 DER Support of Grid Voltage

5.1 Reactive Power Capability

In accordance with *IEEE Std 1547™-2018* Clause 5.2, the DER shall be capable of injecting reactive power (over-excited) and absorbing reactive power (under-excited) for active power output levels greater than or equal to the minimum steady-state active power capability (Pmin), or 5% of rated active power, Prated (kW) of the DER, whichever is greater.

AEP has defined the performance category requirements for all DER as shown in Table 7 below. For energy sources where the performance requirements are to be defined by mutual agreement, AEP and the Customer will jointly develop and document the requirements during the interconnection process.

Table 7: Performance Category Requirements by Energy Source

Power Conversion	Prime Mover/Energy Source	Category
Inverter	Solar PV, Battery Energy Storage	Category B
	Wind	Category B
	Internal Combustion Engine	Category B
	Hydrogen Fuel Cell	Mutual Agreement
Synchronous generator	Bio-/landfill gas, fossil fuel, hydro, combined heat and power	Category A
Induction generator	Hydro	Mutual Agreement

5.2 Reactive Power Control

In accordance with *IEEE Std 1547™-2018* Clause 5.1, the Area EPS Operator shall specify the DER performance category that is required.

As the Area EPS Operator, AEP requires the default settings shown in Table 8 below be applied to connected DER. Site-specific modifications to these settings shall only be made at AEP's request. AEP reserves the right to change the DER reactive power control mode and settings.

Table 8: Reactive Power Control Settings

CONSTANT POWER FACTOR MODE (Specified Power Factor)	Standard Parameter Root Label (based on 1547.1 and modified by EPRI)	UNITS	Utility-Required Setting	Default, Valid, Invalid	IEEE Std 1547™-2018 Category B		
					Default	Min	Max
Constant Power Factor Mode	CONST_PF_MODE_ENABLE-SS	Mode	Enabled	Default	Enabled	Enabled	Disabled
Constant Power Factor Excitation	CONST_PF_EXCITATION-SS	Mode	INJ	Default	INJ	ABS	INJ
Constant Power Factor setting	CONST_PF-SS	PF	1	Valid	-	0.90	1.00

Table 8: (continued) Reactive Power Control Settings

CONSTANT REACTIVE POWER MODE	Standard Parameter Root Label (based on 1547.1 and modified by EPRI)	UNITS	Utility-Required Setting	Default, Valid, Invalid	IEEE Std 1547™-2018 Category B		
					Default	Min	Max
Constant Reactive Power Mode Enable	CONST_Q_MODE_ENABLE-SS	Mode	Disabled	Default	Disabled	Enabled	Disabled
Constant Reactive power setting	CONST_Q-SS	% S	0	Default	0	-44.00	44.00

Table 8: (continued) Reactive Power Control Settings

VOLT-REACTIVE POWER (Volt-Var Mode, Q(V), Voltage-Droop)		Standard Parameter Root Label (based on 1547.1 and modified by EPRI)	UNITS	Utility-Required Setting	Default, Valid, Invalid	IEEE Std 1547™-2018 Category B		
						Default	Min	Max
Voltage-Reactive Power Mode Enable		QV_MODE_ENABLE-SS	Mode	Disabled	Default	Disabled	Enabled	Disabled
Near Nominal	Vref	QV_VREF-SS	V p.u.	1.00	Default	1.00	0.95	1.05
	Autonomous Vref Adjustment Enable	QV_VREF_AUTO_MODE-SS	Mode	Disabled	Default	Enabled	Enabled	Disabled
	Vref adjustment time Constant	QV_VREF_OLRT-SS	s	-	Default	-	300	5000
Point 2	V/Q Curve Point V2 Setting	QV_CURVE_V2-SS	V p.u.	0.980	Default	0.980	0.920	1.05

VOLT-REACTIVE POWER (Volt-Var Mode, Q(V), Voltage-Droop)		Standard Parameter Root Label (based on 1547.1 and modified by EPRI)	UNITS	Utility-Required Setting	Default, Valid, Invalid	IEEE Std 1547™-2018 Category B		
						Default	Min	Max
	V/Q Curve Point Q2 Setting	QV_CURVE_Q2-SS	Q p.u.	0.00	Default	0.00	-1.00	1.00
Point 3	V/Q Curve Point V3 Setting	QV_CURVE_V3-SS	V p.u.	1.020	Default	1.020	0.95	1.08
	V/Q Curve Point Q3 Setting	QV_CURVE_Q3-SS	Q p.u.	0.00	Default	0.00	-1.00	1.00
Point 1	V/Q Curve Point V1 Setting	QV_CURVE_V1-SS	V p.u.	0.92	Default	0.92	0.77	1.03
	V/Q Curve Point Q1 Setting	QV_CURVE_Q1-SS	Q p.u.	0.44	Default	0.44	0.00	1.00
Point 4	V/Q Curve Point V4 Setting	QV_CURVE_V4-SS	V p.u.	1.08	Default	1.08	0.97	1.23
	V/Q Curve Point Q4 Setting	QV_CURVE_Q4-SS	Q p.u.	-0.44	Default	-0.44	-1.00	0.00
QV Open Loop Response Time Setting		QV_OLRT-SS	s	5	Default	5	1	90

Table 8: (continued) Reactive Power Control Settings

ACTIVE POWER-REACTIVE POWER (Watt-Var Mode, Q(P))		Standard Parameter Root Label (based on 1547.1 and modified by EPRI)	UNITS	Utility-Required Setting	Default , Valid, Invalid	IEEE Std 1547™-2018 Category B		
						Default	Min	Max
Active Power Reactive Power Mode Enable		QP_MODE_ENABLE-SS	Mode	Disabled	Default	Disabled	Enabled	Disabled
Active Power, Generation	P-Q curve P3 Setting	QP_CURVE_P3_GEN-SS	P p.u.	1.00	Default	1.00	0.60	1.00
	P-Q curve P2P-Q Setting	QP_CURVE_P2_GEN-SS	P p.u.	0.50	Default	0.50	0.40	0.80
	P-Q curve P1 Setting	QP_CURVE_P1_GEN-SS	P p.u.	0.20	Default	0.20	0.00	0.70
Active Power, Absorption	P-Q curve P3 Setting	QP_CURVE_P1_LOAD-SS	P p.u.	-0.20	Default	-0.20	-0.70	0.00
	P-Q curve P3 Setting	QP_CURVE_P2_LOAD-SS	P p.u.	-0.50	Default	-0.50	-0.80	-0.40
	P-Q curve P3 Setting	QP_CURVE_P3_LOAD-SS	P p.u.	-1.00	Default	-1.00	-1.00	-0.50

ACTIVE POWER-REACTIVE POWER (Watt-Var Mode, Q(P))		Standard Parameter Root Label (based on 1547.1 and modified by EPRI)	UNITS	Utility-Required Setting	Default, Valid, Invalid	IEEE Std 1547™-2018 Category B		
						Default	Min	Max
Reactive Power, Generation	P-Q curve P3 Setting	QP_CURVE_Q3_GEN-SS	S p.u.	-0.44	Default	-0.44	-1.00	1.00
	P-Q curve P3 Setting	QP_CURVE_Q2_GEN-SS	Q p.u.	0.00	Default	0.00	-1.00	1.00
	P-Q curve P3 Setting	QP_CURVE_Q1_GEN-SS	Q p.u.	0.00	Default	0.00	-1.00	1.00
Reactive Power, Absorption	P-Q curve P3 Setting	QP_CURVE_Q1_LOAD-SS	Q p.u.	0.00	Default	0.00	-1.00	1.00
	P-Q curve P3 Setting	QP_CURVE_Q2_LOAD-SS	Q p.u.	0.00	Default	0.00	-1.00	1.00
	P-Q curve P3 Setting	QP_CURVE_Q3_LOAD-SS	S p.u.	0.44	Default	0.44	-1.00	1.00

5.3 Active Power Control

In accordance with *IEEE Std 1547™-2018* Clause 5.4, Category B DER shall provide a voltage regulation capability by changes of active power. Enabling/disabling this function is at the discretion of the Area EPS Operator.

As the Area EPS Operator, AEP requires the default settings shown in Table 9 below be applied to connected DER. Site-specific modifications to these settings shall only be made at AEP's request. AEP reserves the right to change the DER active power control mode and settings.

Table 9: Active Power Control Settings

VOLT-ACTIVE POWER MODE (Volt-Watt Mode, P(V))		Standard Parameter Root Label (based on 1547.1 and modified by EPRI)	UNITS	Utility-Required Setting	Default, Valid, Invalid	IEEE Std 1547™-2018 Category B		
						Default	Min	Max
Voltage-Active Power Mode Enable		PV_MODE_ENABLE-SS	Mode	Disabled	Default	Disabled	Enabled	Disabled
Point 1	PV Curve Point V1 Setting	PV_CURVE_V1-SS	V p.u.	1.06	Default	1.06	1.05	1.09
	PV Curve Point P1 Setting	PV_CURVE_P1-SS	P p.u.	1.00	Default	1.00	-	-
Point 2	PV Curve Point V2 Setting	PV_CURVE_V2-SS	V p.u.	1.10	Default	1.10	1.06	1.10
	PV Curve Point P2 gen Setting	PV_CURVE_P2_GEN-SS	P p.u.	Pmin	Default	Pmin	Pmin	1.00
	PV Curve Point P'2 load Setting	PV_CURVE_P2_LOAD-SS	P p.u.	0.00	Default	0.00	0.00	P'rated
P(V) Open Loop Response Time Setting		PV_OLRT-SS	s	10	Default	10	0.5	60

6.0 DER Response to Abnormal Conditions

In accordance with *IEEE Std 1547™-2018* Clause 6.1, the Area EPS Operator, as guided by the authority governing interconnection requirements who determined applicability of the performance categories as outlined in *IEEE Std 1547™-2018* Clause 4.3, shall specify which of abnormal operating performance Category I, Category II, or Category III performance is required.

The AEP-required DER Response Categories by energy source are specified in Table 10 below.

Table 10: Required Assignment of Abnormal Performance Categories to Various Types of DERs

Power Conversion	Prime Mover/Energy Source	Response Category
Inverter	Solar PV, Battery Energy Storage	Category III[a] (amended)
	Wind	Category II
	Hydrogen Fuel Cell	Mutual Agreement
Synchronous generator	Bio-/landfill gas, fossil fuel, hydro, combined heat and power	Category I
Induction generator	Hydro	Mutual Agreement

[a] was Category II prior to Amendment[5]

6.1 Area EPS Faults

In accordance with *IEEE Std 1547™-2018* Clause 6.2.1, for short-circuit faults on the Area EPS circuit section to which the DER is connected, the DER shall *cease to energize* and trip unless specified otherwise by the Area EPS Operator. This requirement shall not be applicable to faults that cannot be detected by the Area EPS protection systems.

6.2 Open-Phase Conditions

In accordance with *IEEE Std 1547™-2018* Clause 6.2.2, the DER shall detect and *cease to energize* and trip all phases to which the DER is connected for any open-phase condition occurring directly at the RPA and applicable voltage. The DER shall *cease to energize* and trip within 2.0 seconds of the open-phase condition.

5 https://standards.ieee.org/standard/1547a-2020.html

6.3 Area EPS Reclosing Coordination

In accordance with *IEEE Std 1547™-2018* Clause 6.3, appropriate means shall be implemented to help ensure that Area EPS automatic reclosing onto a circuit remaining energized by the DER does not expose the Area EPS to unacceptable stresses or disturbances due to differences in instantaneous voltage, phase angle, or frequency between the separated systems at the instant of the reclosure (e.g., out-of-phase reclosing).

AEP expects appropriate means to be implemented by the Customer and coordinated with AEP. The Customer is solely responsible for the protection of their equipment from automatic reclosing that may occur in the Area EPS.

6.4 Voltage Ride-Through Capability Requirements and Trip Settings

In accordance with *IEEE Std 1547™-2018* Clause 6.4.1, when any applicable voltage is less than an undervoltage threshold, or greater than an overvoltage threshold, as defined in the IEEE subclause, the DER shall *cease to energize* the Area EPS and trip within the respective clearing time as indicated.

As the Area EPS Operator, AEP requires the default settings shown in Table 11 through Table 13 below be applied to connected DER for the different response categories. Site-specific modifications to these settings shall only be made at AEP's request. AEP reserves the right to change the voltage ride-through capability requirements and trip settings.

Table 11: Voltage Trip Settings for Category I-based DERs

Mandatory Voltage Tripping Characteristics		Standard Parameter Root Label (based on 1547.1 and modified by EPRI)	UNITS/ MODE	Utility-Required Setting	Default, Valid, Invalid	IEEE Std 1547-2018 Category I		
						Default	Min	Max
OV2	HV Trip Curve Point OV2 Setting	OV2_TRIP_V-SS	V p.u.	1.20	Default	1.20	-	-
	HV Trip Curve Point OV2 Setting	OV2_TRIP_T-SS	s	0.16	Default	0.16	-	-
OV1	HV Trip Curve Point OV1 Setting	OV1_TRIP_V-SS	V p.u.	1.10	Default	1.10	1.10	1.20
	HV Trip Curve Point OV1 Setting	OV1_TRIP_T-SS	s	2.0	Default	2.00	1.00	13.00
UV1	LV Curve Trip Point UV1 Setting	UV1_TRIP_V-SS	V p.u.	0.70	Default	0.70	0.00	0.88
	LV Curve Trip Point UV1 Setting	UV1_TRIP_T-SS	s	2.0	Default	2.00	2.00	21.00
UV2	LV Curve Trip Point UV2 Setting	UV2_TRIP_V-SS	V p.u.	0.45	Default	0.45	0.00	0.50
	LV Curve Trip Point UV2 Setting	UV2_TRIP_T-SS	s	0.16	Default	0.16	0.16	2.00

Table 12: Voltage Trip Settings for Category II-based DERs

Mandatory Voltage Tripping Characteristics		Standard Parameter Root Label (based on 1547.1 and modified by EPRI)	UNITS/ MODE	Utility-Required Setting	Default, Valid, Invalid	IEEE Std 1547-2018 Category II		
						Default	Min	Max
OV2	HV Trip Curve Point OV2 Setting	OV2_TRIP_V-SS	V p.u.	1.20	Default	1.20	-	-
	HV Trip Curve Point OV2 Setting	OV2_TRIP_T-SS	s	0.16	Default	0.16	-	-
OV1	HV Trip Curve Point OV1 Setting	OV1_TRIP_V-SS	V p.u.	1.10	Default	1.10	1.10	1.20
	HV Trip Curve Point OV1 Setting	OV1_TRIP_T-SS	s	2.0	Default	2.00	1.00	13.00
UV1	LV Curve Trip Point UV1 Setting	UV1_TRIP_V-SS	V p.u.	0.70	Default	0.70	0.00	0.88
	LV Curve Trip Point UV1 Setting	UV1_TRIP_T-SS	s	10.0	Default	10.00	2.00	21.00
UV2	LV Curve Trip Point UV2 Setting	UV2_TRIP_V-SS	V p.u.	0.45	Default	0.45	0.00	0.50
	LV Curve Trip Point UV2 Setting	UV2_TRIP_T-SS	s	0.16	Default	0.16	0.16	2.00

Table 13: Voltage Trip Settings for Category III-based DERs

Mandatory Voltage Tripping Characteristics		Standard Parameter Root Label (based on 1547.1 and modified by EPRI)	UNITS/ MODE	Utility-Required Setting	Default, Valid, Invalid	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	Default	1.20	-	-
	HV Trip Curve Point OV2 Setting	OV2_TRIP_T-SS	S	0.16	Default	0.16	-	-
OV1	HV Trip Curve Point OV1 Setting	OV1_TRIP_V-SS	V p.u.	1.10	Default	1.10	1.10	1.20
	HV Trip Curve Point OV1 Setting	OV1_TRIP_T-SS	S	13.0	Default	13.00	1.00	13.00
UV1	LV Curve Trip Point UV1 Setting	UV1_TRIP_V-SS	V p.u.	0.88	Default	0.88	0.00	0.88
	LV Curve Trip Point UV1 Setting	UV1_TRIP_T-SS	S	21.0	Default	21.00	2.00	50.00
UV2	LV Curve Trip Point UV2 Setting	UV2_TRIP_V-SS	V p.u.	0.50	Default	0.50	0.00	0.50
	LV Curve Trip Point UV2 Setting	UV2_TRIP_T-SS	S	2.00	Default	2.00	0.16	21.00

6.5 Frequency Ride-Through Capability Requirements and Trip Settings

All connected DER shall perform in accordance with the frequency performance requirements as specified in *IEEE Std 1547™-2018* Clause 6.5. In accordance with *IEEE Std 1547™-2018* Clause 6.5.1, DER shall be designed to provide the frequency disturbance ride-through capability specified in this IEEE clause without exceeding DER capabilities.

As the Area EPS Operator, AEP requires the abnormal frequency trip settings shown in Table 14 below be applied to connected DER for the different response categories. Site-specific modifications to these settings shall only be made at AEP's request. AEP reserves the right to change these DER frequency trip settings.

Table 14: AEP-Required Abnormal DER Frequency Trip Settings

Shall Trip Function	Default Settings		Ranges of Allowable Settings	
	Frequency (Hz)	**Clearing Time (s)**	**Frequency (Hz)**	**Clearing Time (s)**
OF2	62.0	0.16	61.8-66.0	0.16-1000
OF1	61.2	300.0	61.0-66.0	180.0-1000
UF1	58.5	300.0[c]	50.0-59.0	180.0-1000
UF2	56.5	0.16	50.0-57.0	0.16-1000

[c] This time shall be chosen to coordinate with typical regional underfrequency load shedding programs and expected frequency restoration time.

7.0 Protection Coordination Requirements

AEP will determine the bus and line configurations and the protection requirements that are necessary to connect the proposed DER to the Area EPS. This section provides protection guidelines and requirements of the most commonly used configurations for parallel DER operation. Protection requirements for a specific DER facility may be greater than those listed, based upon existing or proposed system conditions. In the case of larger DER facilities that include a solar PV DER facility with multiple inverters or other certified equipment, additional equipment may be required to provide adequate protection of the distribution system. Requirements for additional protective equipment due to parallel operation of DERs will vary depending on the capacity (MW) of the DER facility and on the configuration of the Area EPS.

Typical protection requirements for all sites are covered in this section. Typical one-line diagrams are provided in Appendix C: Typical One-Line Diagrams.

7.1 Unintentional Islanding Detection

As required by *IEEE Std 1547™-2018* Clause 8.1, for an unintentional island in which the DER energizes a portion of the Area EPS through the PCC, the DER shall detect the island, *cease to energize* the Area EPS, and trip within 2.0 seconds of the formation of the island. False detection of an unintentional island that does not actually exist shall not justify non-compliance with ride-through requirements as specified in *IEEE Std 1547™-2018* Clause 6.

In addition, AEP requires that a connected DER identify and disclose the method of unintentional islanding detection for DER installations with a total aggregate capacity of 200 kW or greater.

7.2 Intentional Islanding

AEP will allow for interconnected DER to form an intentional island that operates totally within the bounds of a Local EPS. Only DER that are contractually owned or operated by AEP to provide islanding service (including customer owned DER assets) may serve facilities in the Area EPS in an intentional island.

Note: While interconnected to the AEP Area EPS, the DER meant to support an islanded Local EPS shall comply with all of the requirements in this document.

7.3 Direct Transfer Trip Protection

AEP may require the application of Direct Transfer Trip (DTT) on a project-by-project basis, depending on the conditions of the Area EPS where the DER is proposing to connect or satisfy any DER interconnecting Customer performance expectations. Should DTT need to be installed, then the Customer shall procure, install, and own the equipment at their facility per AEP requirements.

The following instances are situational examples that can result in installation of DTT:

- DTT can be added if requested by the Customer after consultation with AEP. Examples of why the Customer might request DTT include:
  - DER cannot disconnect prior to transmission high speed reclosing (HSR) scheme.
  - DER cannot disconnect prior to reclosing of distribution feeder breakers or line reclosers.
- DTT may also be necessary in situations where Under Frequency Load Shed (UFLS) or Under Voltage Load Shed (UVLS) are used.

AEP Transmission Field Services is responsible for the installation of protection and control equipment in AEP distribution stations, and the Customer is responsible for the installation of equipment in their facility. Testing of a DTT circuit between the AEP distribution station and the Customer facility shall be coordinated between AEP Transmission Field Services and the Customer.

7.4 DER Protection Systems Requirements

A DER integrated in the Area EPS shall have its own protection system and shall not depend on AEP to trip, protect, or isolate itself from the distribution system. The Applicant is also responsible for their system's stability and providing adequate facilities so that critical fault clearing times are met.

DER protection systems shall include, but not be limited to, phase and ground fault overcurrent protection and shall be subject to AEP review. This protection is required to be coordinated with AEP's protection devices and shall also be coordinated with voltage ride-through requirements.

The interconnecting Customer shall provide details of their DER protection system and relevant studies and models at AEP's request, including any revised final drawings.

The Applicant shall make changes that AEP requires prior to parallel operation.

7.5 Review and Retention of Protection and Automation Settings

Protection and automation device settings are required to be coordinated, reviewed, and documented between AEP and the DER owner. Setting changes to protection and automation equipment that affects the operation of Area EPS-connected DER shall be reviewed by AEP prior to being applied for in-service operation. Setting files for applicable equipment, or setting summary documentation, shall be submitted by the DER owner to the applicable AEP Operating Company for review.

Any protective relay, control device, inverter controller, etc. that is affected by a material modification as outlined in Section 1.3 shall trigger a review of any affected or adjacent device settings by AEP and the DER owner. If a setting change affects the ability of the DER device or protection equipment to respond to grid events, system faults, voltage sag/swell, or other real-time system abnormalities, the settings shall be re-coordinated even without a material modification.

All communication regarding device settings shall be conveyed electronically in writing to AEP by the DER owner or the owner's authorized representative. All proposed device setting changes shall be itemized by the setting initiator and provided for review before being applied at the device and placed into service. The DER owner shall retain records of the approved settings documentation for a minimum of three years following the in-service date of the settings.

8.0 Power Quality

DER operating in parallel with the Area EPS shall not adversely impact the power quality of the Area EPS or other connected customers.

The Customer shall provide, at AEP's request, evidence confirming the conformance of installed DER equipment to the power quality requirements presented in this section.

AEP reserves the right to request of the Customer, or perform itself, field or laboratory power quality measurements to confirm the performance of connected DER Facilities at any point in the life of the DER facility. If field or laboratory power quality measurements are requested, certified power quality measurement equipment shall be used.

8.1 Limitation of DC Injection

In accordance with *IEEE Std 1547™-2018* Clause 7.1, the DER shall not inject direct current (DC) greater than 0.5% of the full rated output current at the RPA.

8.2 Voltage Fluctuations

In accordance with *IEEE Std 1547™-2018* Clause 7.2.1, the DER shall not create unacceptable rapid voltage changes (RVC) or flicker at the point of common coupling (PCC).

8.2.1 Rapid Voltage Changes (RVC)

In accordance with *IEEE Std 1547™-2018* Clause 7.2.2, when the PCC is at medium voltage, the DER shall not cause step or ramp changes in the RMS voltage at the PCC exceeding 3% of nominal and exceeding 3% per second averaged over a period of one second. When the PCC is at low voltage, the DER shall not cause step or ramp changes in the RMS voltage exceeding 5% of nominal and exceeding 5% per second averaged over a period of one second. Any exception to the limits is subject to approval by the Area EPS Operator with consideration of other sources of RVC within the Area EPS. These RVC limits shall apply to sudden changes due to frequent energization of transformers, frequent switching of capacitors or from abrupt output variations caused by DER mis-operation. These RVC limits shall not apply to infrequent events such as switching, unplanned tripping, or transformer energization related to commissioning, fault restoration, or maintenance.

8.2.2 Flicker Emissions

In accordance with *IEEE Std 1547™-2018* Clause 7.2.3, the DER contribution (emission levels) to the flicker, measured at the PCC, shall not exceed the greater of the limits listed in *Table 25* of the standard (shown as Table 15 below) and the individual emission limits defined by IEC/TR 61000-3-7. Any exception to the limits shall be approved by Area EPS Operator with consideration of other sources of flicker within the Area EPS.

Assessment and measurement methods for flicker are defined in IEEE Std 1453 and IEC/TR 61000-3-7.

Table 15: Minimum Individual DER Flicker Emission Limits[a]

E_{Pst}	E_{Plt}
0.35	0.25

[a]95% probability value should not exceed the emission limit based on a one week measurement period.

8.3 Current Distortion

In accordance with *IEEE Std 1547™-2018* Clause 7.3, harmonic current distortion, inter-harmonic current distortion, and total rated-current distortion (TRD) at the reference point of applicability (RPA) shall not exceed the limits stated in *Table 26* and *Table 27* of the standard (shown as Table 16 and Table 17 below).

Table 16: Maximum Odd Harmonic Current Distortion in Percent of Rated Current (Irated)a

Individual odd harmonic order h	$h < 11$	$11 \leq h < 17$	$17 \leq h < 23$	$23 \leq h < 35$	$35 \leq h < 50$[109]	Total rated current distortion (TRD)
Percent (%)	4.0	2.0	1.5	0.6	0.3	5.0

[a]I_{rated} = the DER unit rated current capacity (transformed to the RPA when a transformer exists between the DER unit and the RPA).

Table 17: Maximum Even Harmonic Current Distortion in Percent of Rated Current (Irated)a

Individual even harmonic order h	$h = 2$	$h = 4$	$h = 6$	$8 \leq h < 50$
Percent (%)	1.0	2.0	3.0	Associated range specified in Table 26

[a]I_{rated} = the DER unit rated current capacity (transformed to the RPA when a transformer exists between the DER unit and the RPA).

8.4 Compatibility with Voltage Regulation Equipment

The DER shall not cause excessive operation of AEP-owned voltage regulators, tap changers, and voltage or VAR-switched capacitors. Rapid changes, where the voltage recovers in less than 10 seconds, are excluded from this requirement.

The following change limits assume a 50% of plant rating rapid output change and apply to minimize excessive voltage regulating equipment operations:

- **Voltage Regulators**: Voltage changes are limited to ½ the bandwidth of any voltage regulator (line or substation) measured at the regulating device.
- **Capacitors**: Voltage changes are limited to ½ the net dead bandwidth of any switched capacitor bank measured at the device.
- **VAR Switched Capacitors**: Reactive power changes are not to exceed ½ the bandwidth of any VAR switched capacitor bank measured at the device.

9.0 Grid Integration Requirements for Radial-Connected DER

9.1 General Requirements

AEP's integration requirements for radial-connected DERs address the compatibility of the DER facility at the PCC and along the feeder, both on the utility side and Customer side of the PCC.

This section contains the technical limits that will be applied during the technical review steps of individual DER or groups of DER connected to the same facilities. AEP may apply increasing level of reviews as a function of the size, location, and complexity of the proposed DER.

9.1.1 Explanation of the Reviewed Impacts

As part of the DER interconnection process, AEP will review or assess the following technical impacts from the proposed DER(s):

- **Steady State Voltage Analysis**: Simulations may be performed to determine how the voltage in the Area EPS will change as a result of the DER operation. Multiple Area EPS operating scenarios or DER control parameters may be considered.
- **Thermal Impact Analysis**: Simulations may be performed to determine how the current in the Area EPS will change as a result of the DER operation. Multiple Area EPS operating scenarios or DER control parameters may be considered.
- **Short Circuit Analysis**: Simulations may be performed to determine the incremental contribution of the DER to available fault current in the Area EPS or to determine fault current impacts on individual Area EPS components and protection devices. Multiple Area EPS operating scenarios or DER control parameters may be considered.
- **Reverse Power Flow Analysis**: Simulations may be performed to determine the amount and frequency of power moving from the distribution system to the transmission system due to the proposed DER(s). Multiple Area EPS operating scenarios or DER control parameters may be considered.

For all of these reviewed impacts, if a DER is determined to reach or exceed any of the limits captured in Sections 9.2 through 9.9, mitigation shall be required. It will be developed through the interconnection process and implemented prior to DER operation. The proposed mitigation may include site-specific customized DER control and response settings.

9.2 Steady State Voltage Limits

The AEP steady state voltage limits are based on the ANSI C84.1 Range A limits for primary and secondary distribution systems. Table 18 below documents the operating limits established by AEP for steady state voltage during normal or contingency conditions.

Table 18: AEP Steady State Distribution System Voltage Limits

	Low Voltage Boundary	Upper Voltage Boundary
Primary Voltage (120 V base)	117	126
Secondary Voltage (120 V base)	114	126

Note: In the State of Virginia the tariff in effect allows for the Low voltage boundary for Primary Voltage in rural areas to be set at 114 V (on a 120 V base).

9.3 Thermal Impact Limits

9.39.8All thermal ratings considered shall be based on unbalanced load conditions. The thermal limit of all protective devices (e.g., breakers, reclosers, and fuses) across the AEP distribution system will be evaluated at 90% of their continuous rating.

9.3.1 Station Transformer Limits

Distribution station power transformer loading shall be limited to 90% of their normal seasonal capability rating.

9.3.2 Distribution Service Transformer Limits

Distribution line transformer loading shall be limited to no greater than the nameplate kVA rating when operating in a reverse power flow direction.

9.3.3 Distribution Feeder Limits

Table 19: Distribution Feeder Thermal Limits

	Normal Loading (% of Maximum Capability Rating)	Contingency Loading (% of Maximum Capability Rating)
Feeder Exit	90%	100%
Branch Feeder Sections	90%	100%

9.3.4 Distribution Voltage Regulator Limits

Table 20: Voltage Regulator Thermal Limits

	Normal Loading (% of Max Nameplate Rating +/- 10% Regulation)	Contingency Loading (% of Max Nameplate Rating +/- 10% Regulation)
Bus Voltage Regulators	90%	100%
Load Tap Changers (LTC)	90%	100%
Line Voltage Regulators	90%	100%

9.4 Short Circuit Limits

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

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

9.5 Reverse Power Flow Limits

A DER connected to the AEP distribution system is permitted to inject power from the distribution system to the transmission system, as long as it does not result in any transmission system impacts or any distribution impacts that exceed any of the limits set forth in this document.

All proposed DER interconnections that can potentially create reverse power from the distribution system to the transmission system will be reviewed for compliance and adherence to AEP Transmission System Planning criteria and relevant transmission system tariffs.

9.6 Limits for DER Customers with Multiple Radial Services

When a DER Customer has multiple normal service connections to the Area EPS or can be fed from multiple distribution feeders, regardless of whether the electrical connections are through AEP-owned equipment or Customer-owned equipment, the DER operational limits shall be determined based upon the feasibility to operate from:

- All possible feeds
- A reduced set of feeds, as long as a mechanism is installed to trip the DER before the Customer location is transferred to a feed that has not been evaluated

In all situations, the ultimate operation of the DER shall be limited based upon the most constrained evaluated connection configuration, per the limits contained in this document.

9.7 DER Operation During Abnormal Conditions

DER connected to the Area EPS shall only operate in distribution system configurations for which the DER has been approved, and for which any required mitigations have been put in place.

DER that is transferred to another feed during manual or automated switching operations, such as during the operation of Distribution Automation schemes, shall be removed from service if not previously studied or reviewed by the Area EPS Operator.

For Customer locations where switchgear is equipped with alternate feeds, and employs automatic-transfer capability, 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 shall be tripped before the Customer is transferred to the alternate source.

9.8 DER Output Self-Limiting

DER connected to the Area EPS will be allowed to self-limit their real power output, below their nameplate capacity, through DER Facility settings or controls to limit their overall capacity or address identified performance issues or operational requirements. The Customer shall provide AEP with the technical details of how it implements output self-limiting.

AEP will allow the following methods for output self-limiting (also known as "limited-export”):

- A reverse power protective function may be provided, with a default setting for this protective function of 0.1% export of the service transformer’s rating, with a maximum 2.0 second time delay.
- An under-power protective function may be provided, with a default setting for this protective function of 5% import of the DER’s total nameplate rating, with a maximum 2.0 second time delay.
- The nameplate rating of the DER, minus any auxiliary load, must 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 is not exported to the distribution system. This option requires the DER capacity must be no greater than 50% of the Applicant’s verifiable minimum host load over the past 12 months. The customer will be responsible for disabling the DER when their load falls below the value specified in the interconnection agreement.
- A reduced output rating utilizing the power rating configuration setting may be used to ensure the DER does not generate power beyond a certain value lower than the nameplate rating.
- DERs may utilize a Nationally Recognized Testing Laboratory Certified Power Control System and inverter system that results in the DER disconnecting from the distribution system, ceasing to energize the distribution system, or halting energy production within two seconds if the period of continuous inadvertent export exceeds 30 seconds. Failure of the control or inverter system for more than 30 seconds, resulting from loss of control or measurement signal, or loss of control power, must result in the DER entering an operational mode where no energy is exported across the point of common coupling to the distribution system.
- DERs may be designed with other control systems or protective functions, or both, to limit export and inadvertent export to levels mutually agreed on by the Applicant and AEP. The limits may be based on technical limitations of the Applicant’s equipment or the distribution system’s equipment. To ensure inadvertent export remains within mutually agreed-upon limits, the Applicant shall use an internal transfer relay, energy management system, or other customer facility hardware or software.

AEP reserves the right to require the Customer to implement additional DER self-limiting methods should the original method be deemed insufficient.

9.9 DER Power Factor Requirements

In accordance with *IEEE Std 1547™-2018* Clause 5.2, the DER shall be capable of injecting reactive power (over-excited) and absorbing reactive power (under-excited) for active power output levels greater than or equal to the minimum steady-state active power capability (Pmin), or 5% of rated active power, Prated (kW) of the DER, whichever is greater.

The range of required reactive power capability will be defined by the performance Category (A or B) of the DER, as defined in Table 7 of this document:

- For Category A DERs
  - Injection capability: 0.9 pf
  - Absorption capability: 0.97 pf
- For Category B DERs
  - Injection capability: 0.9 pf
  - Absorption capability: 0.9 pf

Note: In the state of Virginia, wind generators are exempt from this power factor requirement per *VA Administrative Code* Chapter 314, Section 1.8.1.

In addition, DER connected to the Area EPS will be assessed for their impact to the overall power factor of the distribution or transmission facilities that serve the DER. For DER facilities where the DER is collocated with site load (i.e., a residential, commercial, or industrial customer), the Customer shall continue to abide by their contractual power factor requirements when the DER facility becomes operational. AEP reserves the right to request or implement power factor performance adjustments of all connected DER.

10.0 Grid Integration for Network-Connected DER

Network-connected DER must comply with all requirements of this TIIR. This section will reference *IEEE Std 1547™-2018* Clause 9 related specifically to network-connected DER and discusses additional AEP requirements for DER interconnection onto a network system. An engineering review is needed for every interconnection proposal on a network. AEP prohibits the installation of synchronous generator-based DER on grid networks.

AEP has overlapping but different requirements for spot networks and grid networks.

10.1 General Requirements

In accordance with IEEE Std 1547™-2018 Clause 9.1, Network Protectors (NPs) shall not be used to connect, separate, switch, serve as breaker failure backup or in any manner isolate a network or network primary feeder to which DER is connected from the remainder of the network, unless the protectors are rated and tested per applicable standards for such an application.

Unless specified otherwise by AEP, the Area EPS Operator, DER installations on a network, using an automatic transfer scheme in which load is transferred between the DER and the EPS in a momentary make-before-break operation, shall meet all the requirements of this clause regardless of the duration of paralleling. Power flow during this transition shall be positive from the Area EPS to the load and the DER unless approved by and coordinated by the Area EPS Operator.

DER on grid or spot networks shall have provisions to:

- Monitor instantaneous power flow at the PCC (Point of Common Coupling) of the DER interconnected to the secondary grid or spot network for reverse power relaying, minimum import relaying, dynamically controlled inverter functions and similar applications to prevent reverse power flow through network protectors
- Maintain a minimum import level at the PCC as determined by the Area EPS Operator
- Control DER operation or disconnect the DER from the Area EPS based on an autonomous setting at the PCC and/or a signal sent by the Area EPS Operator

DER on grid or spot networks shall not:

- Cause any NP to exceed its loading or fault-interrupting capability
- Cause any NP to separate dynamic sources
- Cause any NP to connect two dynamic systems together
- Cause any NP to operate more frequently than prior to DER operation
- Prevent or delay the NP from opening for faults on the Area EPS
- Delay or prevent NP closure
- Energize any portion of an Area EPS when the Area EPS is de-energized
- Require the NP settings to be adjusted except by consent of the Area EPS Operator

- Prevent reclosing of any network protectors installed on the network that shall be accomplished without requiring any changes to prevailing network protector clearing time practices of the Area EPS

10.2 Grid Networks

IEEE Std 1547™-2018 Clause 9.2 addresses several requirements related to DER integration that are specific to grid networks in addition to the general network requirements addressed in Section 10.1 of this document.

As required by *IEEE Std 1547™-2018* Clause 9.2, DER on secondary grid networks shall not cause an islanding condition within that network. In addition, in the event of an adjacent feeder fault, network protector master relays shall not be actuated by the presence of DER. The interconnected DER shall be coordinated with NP relay functions and shall be evaluated by the Area EPS Operator to ensure network reliability.

As there is a significantly greater impedance of the grid network in relation to the transformers serving the network, it is difficult to determine the amount of reverse power flow that could flow through a protector on the grid network. Because of this, aggregate load of a given DER should not exceed 2% of the grid network's minimum loading level to minimize the risk of reverse power flow through all protectors on the grid network (*IEEE Std 1547.6™-2011* Clause 7.2).

10.3 Spot Networks

IEEE Std 1547™-2018 Clause 9.3 addresses several requirements related to DER integration that are specific to spot networks in addition to the general network requirements addressed in Section 10.1 of this document.

As required by *IEEE Std 1547™-2018* Clause 9.3, connection of the DER to the Area EPS is only permitted if the Area EPS network bus is already energized by more than 50% of the installed network protectors.

At all times, positive power flow shall be maintained so that the DER does not export power to the Area EPS. The DER shall always generate less than DER facility load (*IEEE Std 1547.6™-2018* Clause 7.2). AEP may require the interconnecting DER to install controls or adjust settings to meet these performance requirements.

11.0 DER Facility Interoperability, Telemetry, and Cyber Security

11.1 General Requirements

All DER connected to the Area EPS shall meet the requirements for interoperability as specified in *IEEE Std 1547™-2018* Clause 10 – Interoperability, Information Exchange, Information Models, and Protocols. The DER Customer will work with AEP to implement any required telemetry following AEP's guidance.

This section defines additional AEP requirements and clarifies which systems must be connected to telecommunications networks for data to be collected or exchanged based on nameplate capacity of the DER Facility.

11.1.1 Requirements for DER Installations at or above 500 kW

AEP requires that SCADA telemetry be implemented at both the Plant Controller and the SCADA controlled disconnect switch (where applicable per Section 4.10 of this document) for any DER 500 kW or larger for monitoring and control purposes.

11.1.2 Requirements for DER Installations at or above 200 kW and less than 500 kW

AEP requires that SCADA telemetry be implemented at the Plant Controller for any DER 200 kW or larger for monitoring and control purposes. AEP does not require a remotely controlled disconnect switch for DER installations under 500 kW.

11.1.3 Requirements for DER Installations less than 200 kW

All DER installations must comply with the items defined in *IEEE Std 1547™-2018* Clause 10 – Interoperability, Information Exchange, Information Models, and Protocols in the event that AEP requires any form of telemetry for monitoring and control purposes in the future.

11.1.4 Additional Requirements

Any additional telemetry requirements will be specified by AEP during the interconnection process and documented in the interconnection agreement. AEP reserves the right to use and apply all of the technical and operational information that it gathers from DER connected to the Area EPS.

For DER installations that use a Plant Controller to manage multiple inverters, the Plant Controller shall measure and manage the voltage and aggregate power generation at the PCC or an agreed upon location.

It will be the responsibility of the DER Customer to ensure the quality of the data and information received by AEP from the DER is good (98% and above availability) and accurate. AEP reserves the right to request additional testing (see Section 13.0 of this document) to confirm the accuracy of measurements and to have the Customer remediate measurement issues.

11.2 Interoperability for DER Facilities

The telemetry interface(s) through an RTU that AEP deploys to communicate with DER connected to the Area EPS will be utilized as specified in other parts of this document and in *IEEE Std 1547™-2018* Clause 10 – Interoperability, Information Exchange, Information Models, and Protocols.

11.2.1 DER Nameplate Information

In accordance with *IEEE Std 1547™-2018* Clause 10.3, nameplate information shall be available through a local DER communication interface and include at a minimum the information contained in *Table 28* of the standard (shown as Table 21 below).

Table 21: DER Nameplate Information Required

Parameter	Description
Active power rating at unity power factor (nameplate active power rating)	Active power rating in watts at unity power factor
Active power rating at specified over-excited power factor	Active power rating in watts at specified over-excited power factor
Specified over-excited power factor	Over-excited power factor as described in *Section 5.2* of *IEEE 1547-2018*
Active power rating at specified under-excited power factor	Active power rating in watts at specified under-excited power factor
Specified under-excited power factor	Under-excited power factor as described in *Section 5.2* of *IEEE 1547-2018*
Apparent power maximum rating	Maximum apparent power rating in voltamperes
Normal operating performance category	Indication of reactive power and voltage/power control capability. (Category NB as described in *Section 1.4* of *IEEE 1547-2018*)
Abnormal operating performance category	Indication of voltage and frequency ride-through capability Category I, II, or III, as described in *Section 1.4* of *IEEE 1547-2018*
Reactive power injected maximum rating	Maximum injected reactive power rating in vars
Reactive power absorbed maximum rating	Maximum absorbed reactive power rating in vars
Active power charge maximum rating	Maximum active power charge rating in watts
Apparent power charge maximum rating	Maximum apparent power charge rating in voltamperes. May differ from the apparent power maximum rating
AC voltage nominal rating	Nominal AC voltage rating in RMS volts
AC voltage maximum rating	Maximum AC voltage rating in RMS volts

Parameter	Description
AC voltage minimum rating	Minimum AC voltage rating in RMS volts
Supported control mode functions	Indication of support for each control mode function
Reactive susceptance that remains connected to the Area EPS in the *cease to energize* and trip state	Reactive susceptance that remains connected to the Area EPS in the *cease to energize* and trip state
Manufacturer	Manufacturer
Model	Model
Serial number	Serial number
Version	Version

11.2.2 DER Configuration Information

In accordance with *IEEE Std 1547™-2018* Clause 10.4, configuration information shall be available through a local DER communication interface to allow the setting and reading of the currently active values.

Changes to the configuration settings shall be made with mutual agreement between the DER system operator and AEP. Configuration settings may be used by AEP to deviate from nameplate values. Configuration settings are not intended for continuous dynamic adjustment.

11.2.3 DER Monitoring Information

In accordance with *IEEE Std 1547™-2018* Clause 10.5, the DER shall be capable of providing monitoring information through a local DER communication interface at the reference point of applicability and shall include at a minimum the information contained in Table 29 of the standard (shown as Table 22 below). The information shall be the latest value that has been measured within the required response time.

Table 22: DER Monitoring Information Required

Parameter	Description
Active Power	Active power in watts
Reactive Power	Reactive power in vars
Voltage	Voltage(s) in volts. (One parameter for single-phase systems and three parameters for three-phase systems)
Frequency	Frequency in Hertz
Operational State	Operational state of the DER. The operational state should represent the current state of the DER. The minimum supported states are on and off, but additional states may also be supported

Parameter	Description
Connection Status	Power-connected status of the DER
Alarm Status	Active alarm status
Operational State of Charge	0% to 100% of operational energy storage capacity

11.2.4 DER Management Information

In accordance with *IEEE Std 1547™-2018* Clause 10.6.1, Management information is used to update functional and mode settings for the DER. This information may be read or written.

AEP requires the DER to have available all management information contained in *IEEE Std 1547™-2018* Clauses 10.6.2–10.6.12. This information may be read or written by AEP.

11.3 DER Communication Interface

11.3.1 DER Facility Requirements

In accordance with *IEEE Std 1547™-2018* Clause 10.1, a DER shall have provisions for a local DER interface capable of communicating (local DER communication interface) to support the information exchange requirements specified in the standard for all applicable functions that are supported in the DER.

The DER facility shall use a single local DER communication interface or other AEP-approved communication means to provide all telemetry and control that is required to meet the telemetry requirements identified throughout this document. AEP will specify all necessary communication information sharing requirements for DER interconnection. Specific details of telemetry requirements will be provided during the interconnection process.

11.3.2 AEP DER Integrating Protocol

In accordance with *IEEE Std 1547™-2018* Clause 10.7, the DER shall support at least one of the protocols specified Clause 10.7 of the standard. The protocol to be utilized may be specified by the Area EPS Operator.

As the Area EPS Operator, AEP supports serial *IEEE Std 1815 (DNP3)* and serial Modbus protocols for use as a communication interface.

11.3.3 Unlock Mechanism Requirement

All DERs connecting to the Area EPS shall have an open and unlocked communications interface unless AEP specifically instructs the interconnecting Customer to lock the interface. In the instance of a locked interface, the Customer shall provide documentation to AEP that describes the messages and passcodes for each DER to unlock and relock the DER.

11.3.4 Telemetry-Based and Schedule-Based Charging of BESS

AEP does not currently support telemetry-based or schedule-based charging of battery energy storage systems (BESS). AEP is evaluating options to implement these capabilities and will update this section when it is ready to proceed.

11.4 AEP DER Network Adapters

As required, AEP will provide and install the telemetry and network adapters required for interoperability of the DER Facility with AEP’s communications and control systems. These systems may include such items as communication systems for protocol translation, monitoring DER information, controlling DERs, tripping DER units, and tripping breakers/reclosers. DER network adapters will be required for those installations that are greater than 200 kW that require monitoring.

11.5 DER Facility Cyber Security

The DER facility owner should follow, to the maximum extent possible, the guidance provided in *IEEE Std 1547.3™-2018*, Draft Guide for Cybersecurity of Distributed Energy Resources Interconnected with Electric Power Systems and keep firmware up to date. AEP reserves the right to disconnect DER from the Area EPS for any cyber related concern until the concern is remediated. Ultimately, the DER facility owner is responsible for the Cyber Security of the DER facility.

Further, the DER facility owner should consider, as applicable, the following additional standards:

- IEEE Std 1547.2™-2018
- IEC 62351 series
- ISO/IEC 27000 series
- IEC 62443 series
- UL 2900-2 series
- NISTIR 7628
- NIST cybersecurity framework and other cybersecurity guidelines
- IEEE 1686 revision
- IEEE C37.240 revision
- IETF, Internet cybersecurity standards

12.0 DER Facility Revenue Metering

DER facility revenue metering is required by AEP for all Customers. DER that elect to interconnect to AEP Facilities carry the same requirements. To achieve this requirement, AEP will provide and deploy appropriate facility revenue metering for each DER installation based on the proposed configuration of the DER and its intended purpose, state specific or regional tariff requirements, and AEP's own internal requirements. AEP strives to directly measure and capture the energy produced and consumed by connected DER through standardized metering equipment.

AEP will determine the appropriate site-specific DER Facility revenue metering requirements as part of the DER interconnection process.

12.1 Type of DER Metering Installations

Different types and configurations of DER facility revenue metering arrangements may be employed by AEP to meet the requirements and expectations stated above.

Ultimately, multiple questions will need to be addressed or answered by the Customer to determine the required metering configuration, including:

- What do the state tariffs require?
- What do Regional Transmission Organizations (RTOs) tariffs require? (see Section 12.5).
- Will the DER be providing any type of retail, wholesale, or market services?
- May require telemetry
- What are the technical characteristics, such as size, of the DER Facility?
- May require primary metering (voltage and current transformers) or secondary metering equipment (current transformers)
- What are the characteristics of the system where the DER proposes to connect?

Some examples of the types of DER Facility revenue metering configurations include:

- Single-metered DER (see Section 12.1.1)
- Single-Metered DER will use a bidirectional PCC Meter that will be programmed to register and record energy delivered to the Customer from the utility as well as any excess generation that the Customer puts back onto the Area EPS. These values will be recorded in separate channels of the meter.
- Multi-metered DER (see Section 12.1.2)
- Multi-Metered DER installations will use a bidirectional PCC meter that measures energy delivered to the Customer as well as any excess generation the Customer puts back onto the Area EPS. These installations will also use one or more bidirectional PoC Meters that measure the output of the Customer's DER units. The PoC meter will also be programmed to register and record usage in each direction.

- Some commercial and industrial services require the use of current transformers (CT) and/or voltage transformers (VT). In these cases, the PoC meter will require the use of high accuracy current transformers and voltage transformers.
- Metering CTs shall have a high accuracy, extended range, 0.15% accuracy class or better.
- Metering VTs shall have a high accuracy, 0.15% through Y burden or better.
- Metering circuits shall not be shared with other devices without AEP's approval.

All DER Facility Revenue Metering shall be revenue grade and include bidirectional recording capability to capture energy produced (export) and energy consumed (import) by the DER Facility. A metering enclosure or a pole mounted rack may be required to accommodate the additional CTs and/or VTs.

12.1.1 Single-Metered DER

The application of a single meter at the PCC to capture the bi-directional or effective produced or consumed energy by the Customer, inclusive of any DERs, may be required in some instances.

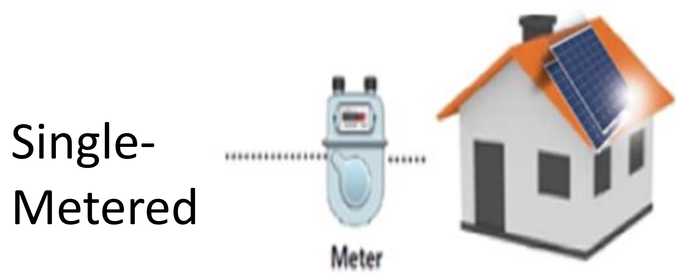


Figure 4: Representative Illustration of a Single-Metered DER Configuration

12.1.2 Multi-Metered DER

Multi-metering of DER at a Customer's facility, where separate loads are also served, may be required in installations where direct measurement of energy produced and consumed by the DER unit(s) is required.

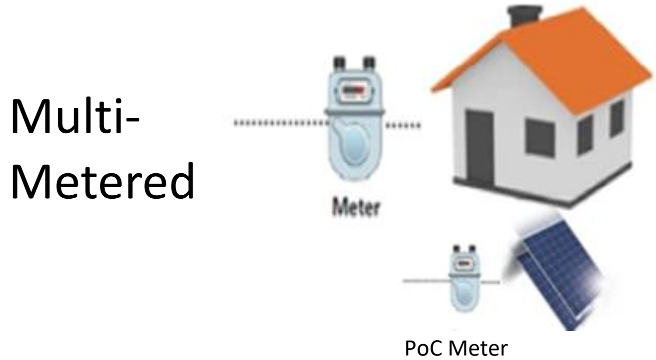


Figure 5: Representative Illustration of a Multi-Metered DER Configuration

12.2 DER Meter Placement for Residential Installations

Due to the high number of residential DERs connecting to the grid, their increasing complexity, and the large number of installers of these types of systems, consistency is required in the installation and placement of the metering equipment at a Customer's premise to ensure the safety, reliability, and fidelity of the meter installation.

For reference, shown in Figure 6 below is AEP's standard Residential DER Metering installation diagram for multi-metered DER installations. For additional details on AEP facility metering requirements please review the "AEP Meter and Service Guide" available at:

https://www.aepnationalcustomers.com/lib/docs/builders/meter/MeterandServiceGuide_2023rev2-11-08-2023.pdf

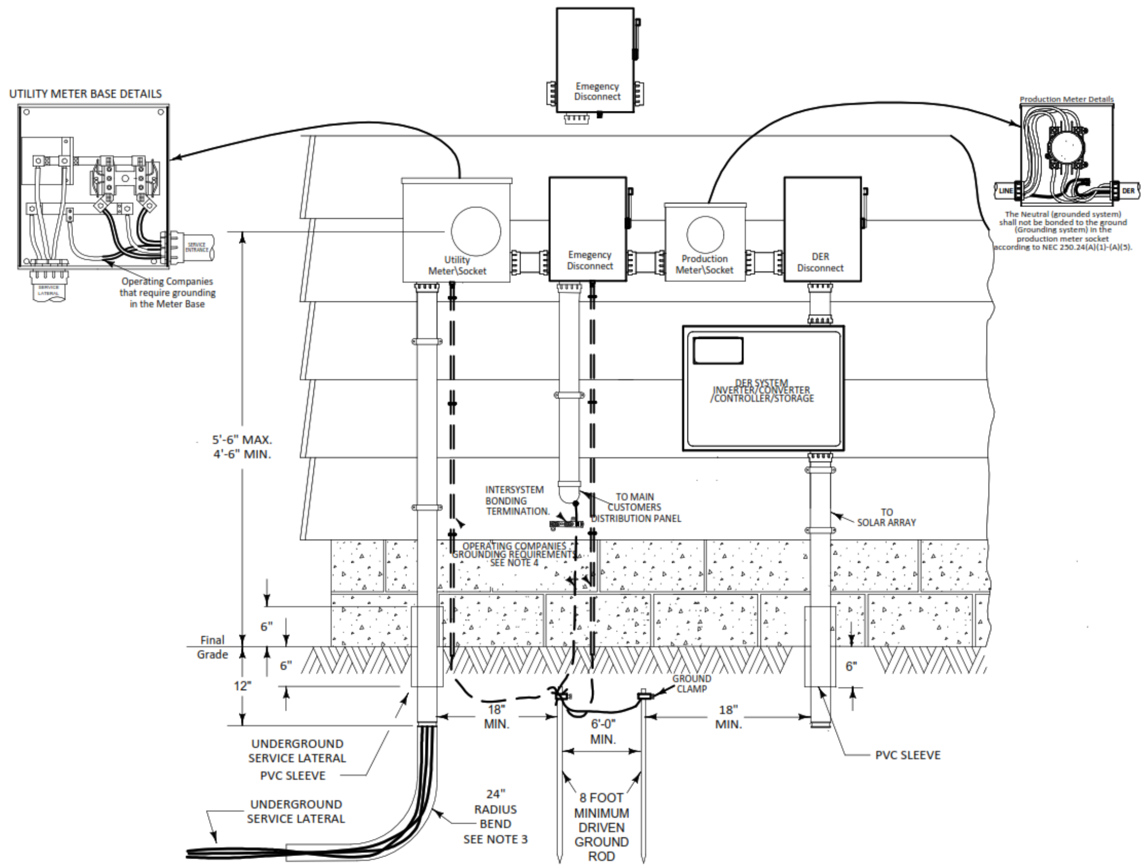


Figure 6: DER Metering Installation Diagram for a Residential Multi-Metered DER

Appendix D: Residential DER system with "Point of Connection Meter Details" and "Point of Common Coupling Meter Details" contains this image and accompanying detailed notes for installation guidance.

12.3 Meter Socket Collar Devices

The following Table 23 identifies the Operating Companies that allow the use of approved meter collar devices. AEP does not own these devices. These devices are owned and maintained by the Customer. In order for the Customer to connect one of these approved devices, an agreement must be signed by the Customer and a nominal fee remitted to cover the cost of installation by an AEP Field Technician. For more information, please review the AEP Meter Service Guide referenced in Section 12.2.

Table 23: Allowed Meter Collars for DER installations

Operating Companies that *Allow* Meter Collars for DER installations	Operating Companies that *Do Not Allow* Meter Collars for DER installations
Appalachian Power	AEP Ohio
	AEP Texas

Operating Companies that *Allow* Meter Collars for DER installations	Operating Companies that *Do Not Allow* Meter Collars for DER installations
	Indiana Michigan Power
	Kentucky Power
	Public Service Oklahoma
	Southwestern Electric Power

Note that multiple AEP operating companies allow the use of a meter collar for home backup power connections.

12.4 Applicable State Tariffs

State tariffs in effect across the AEP system vary in their available DER programs and associated metering requirements.

Special metering, telemetry and other size limitations may be provided in these tariffs.

Links are provided in Table 24 below to the latest tariffs in effect across the AEP system:

Table 24: Latest Tariff Links

Operating Company	Link
AEP Ohio	https://www.aepohio.com/company/about/rates/
AEP Texas	https://www.aeptexas.com/company/about/rates/
Appalachian Power	Tennessee – https://www.appalachianpower.com/company/about/rates/tn Virginia – https://www.appalachianpower.com/company/about/rates/va West Virginia – https://www.appalachianpower.com/company/about/rates/wv
Kentucky Power	https://www.kentuckypower.com/company/about/rates/
Indiana Michigan Power	Indiana - https://www.indianamichiganpower.com/company/about/rates/in Michigan - https://www.indianamichiganpower.com/company/about/rates/mi
Public Service Company of Oklahoma	https://www.psoklahoma.com/company/about/rates/
Southwestern Electric Power	Arkansas - https://www.swepco.com/company/about/rates/ar Louisiana - https://www.swepco.com/company/about/rates/la Texas - https://www.swepco.com/company/about/rates/tx

12.5 Applicable RTO Tariffs

Regional tariffs are in effect across the AEP system. Special metering, telemetry and other size limitations may be provided in these tariffs provided in Table 25:

Table 25: Regional Tariff Links

Operating Company	RTO	Link
AEP Ohio	PJM	https://agreements.pjm.com/oatt/3897
AEP Texas	Electric Reliability Council of Texas (ERCOT)	https://www.ercot.com/mktrules/nprotocols/current
Appalachian Power	PJM	https://agreements.pjm.com/oatt/3897
Kentucky Power	PJM	https://agreements.pjm.com/oatt/3897
Indiana Michigan Power	PJM	https://agreements.pjm.com/oatt/3897
Public Service Company of Oklahoma	Southwest Power Pool (SPP)	https://spp.etariff.biz:8443/viewer/viewer.aspx
Southwestern Electric Power	SPP	https://spp.etariff.biz:8443/viewer/viewer.aspx

12.6 AEP Transmission System Interconnection Requirements

In addition, there are some instances in which proposed DER interconnections may require alignment with or adherence to AEP's Transmission System interconnection requirements. AEP's "Requirements for Connection of New Facilities or Changes to Existing Facilities Connected to the AEP Transmission System" document is publicly available through the AEP website at:

https://www.aep.com/requiredpostings/AEPTransmissionStudies

12.7 Power Quality Metering

DER systems larger than 2.0 MW shall use a Power Quality (PQ) functionality capable revenue meter, that can provide AEP with continuous monitoring and recording of the DER's PQ performance.

13.0 Commissioning and Verification Requirements

13.1 General Requirements

This section covers commissioning and verification activities necessary to confirm that DER installations comply with *IEEE Std 1547™-2018* and AEP's specific requirements. Commissioning and verification requirements are specified in *IEEE Std 1547™-2018* Clause 11 – Test and Verification Requirements and *IEEE Std 1547.1™-2020* Clause 8 - DER evaluations and commissioning tests.

The verification process includes configuration of DER functional settings, evaluation of documentation, and determination of tests required to be completed. References to determine test requirements that depend on the DER facility size and type, as well as any specific protective relay test requirements are provided. This section also covers recommissioning and periodic testing.

Specific commissioning and verification requirements for each project will be communicated during the interconnection process.

Throughout the life of the DER Facility, starting from the interconnection process through ultimate retirement, AEP may perform remote tests of the DER Facility to review its operational capabilities, configuration, telemetry performance, and adherence to the standards and requirements contained within this document. Testing may also be required to help diagnose system issues experienced by other customers on the same feeder or station equipment.

13.2 DER Commissioning Process

Figure 7 illustrates AEP's installation verification, meter change and commissioning process flow for interconnecting DER.

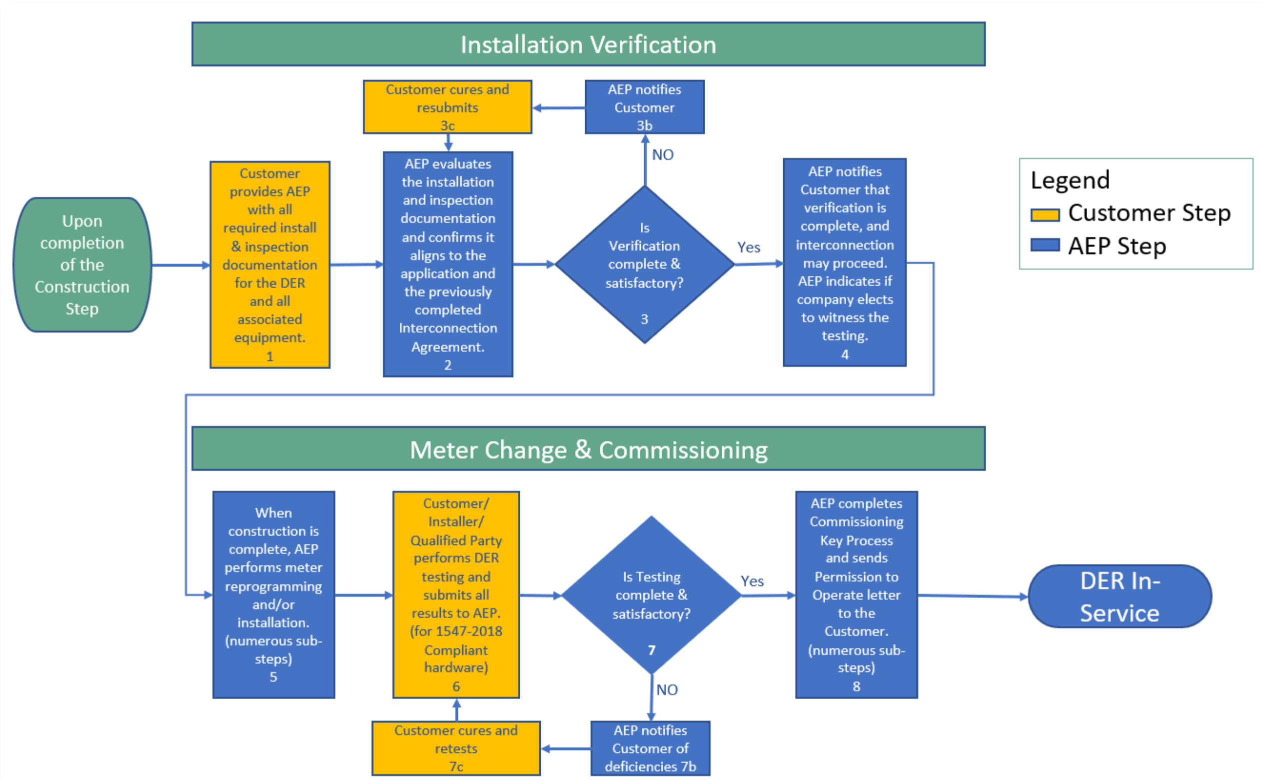


Figure 7: Process Flow for Commissioning-related steps of the DER Interconnection Process

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Note: AEP will require advanced notice of DER testing schedule in order to arrange logistics when AEP elects to witness the testing.

13.3 Configuration of DER Functional Settings

Prior to the start of commissioning testing, the Customer shall configure the DER facility's functional settings in accordance with the default parameters defined in Sections 4.13, 5.2, 5.3, 6.4, and 6.5 in this document, or with site-specific parameters if provided by AEP. Such site-specific parameters would be documented in an exhibit to the Customer's Interconnection Service Agreement.

13.4 Evaluation of Documentation and Installation

Prior to the performance of commissioning tests by the Customer's Qualified Personnel, AEP will evaluate the installation and inspection documentation to confirm that it is consistent with the submitted DER application and other required project documentation. This evaluation will determine whether commissioning can proceed.

The DER Customer shall provide AEP with all required documentation for the installed DER system and for all associated DER equipment.

13.5 DER Commissioning Tests

Commissioning of the DER facility shall be planned by the Customer and carried out according to the approved testing plan after construction is completed and the site is ready to be energized. At a minimum, the scope of commissioning process to be performed shall include commissioning tests specified by *IEEE Std 1547™-2018* Clause 11.2.4.3 - DER as-built installation evaluation, Clause 11.2.5 - Commissioning tests and verifications, and Clause 11.3 - Full and partial conformance testing and verification.

The commissioning process shall demonstrate that the DER facility does not create adverse system impacts to the electric grid and to other customers served by the grid. AEP will require additional testing and analysis for any approved intentional islands that energize Area EPS facilities.

Once AEP has approved the Customer's DER Commissioning Test Plan, the Customer shall provide AEP with 10 business days' notice prior to initial commissioning tests and 48 hours' notice for any required follow-up testing.

Commissioning requirements are dependent on the size of the DER and the DER certification. The following criteria will be considered to identify the commissioning test requirements of the Customer:

- Certification of DER System for RPA at PCC. Classifications include DER System (PCC), or DER Composite for PCC Compliance.
- Results of Technical Review and determination of project-specific settings or Operating Profile.

Commissioning tests shall be performed according to the appropriate requirements of *IEEE Std 1547™-2018* Clause 11, in accordance with *IEEE Std 1547™.1-2020*, and performed by Qualified Personnel. Clause 11 of *IEEE Std 1547™-2018* provides a commissioning requirements matrix. For DER systems with Plant Controllers, commissioning tests shall include the Plant Controller.

In addition to the commissioning test requirements identified in *IEEE Std 1547™-2018*, DER settings shall be verified, and protective relaying shall be tested as identified in Section 13.6*.* Commissioning is also required for telemetry systems and isolation devices depending on DER size and application. Note additional commissioning and witness testing requirements for Secondary Network can be found in Section 10.0*.*

13.6 Protective Relay Tests

Qualified Personnel shall perform tests on the Customer's protective relaying prior to energizing from the Area EPS. Testing requirements will be evaluated and determined on a case-by-case basis by AEP, dependent upon the configuration of the proposed generating facility. Permission to energize from the Area EPS does not indicate permission to operate the DER in parallel with the Area

EPS. A formal *Permission to Operate* notice will be provided to Customer upon successful fulfillment of all Commissioning criteria.

It is the responsibility of the DER Customer to test their protection schemes (which includes DTT) with their own equipment and Qualified Personnel to ensure it is reliable and safe to place in service. During the commissioning phase of the project, the DER Customer will coordinate with AEP Protection and Control (P&C) crews testing the P&C equipment that interacts amongst both companies (each will be located at their own station/facility).

The following Table 26 is provided to serve as guidance and may or may not be prescribed in the Customer's relay equipment inspection requirements.

Table 26: 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	Commissioning
Tripping Check	Commissioning
Sensing Devices	Test Document Review
Primary Current/Voltage	Commissioning
Telemetry for Protection Scheme	Commissioning

The configuration of settings for the protection systems shall be the settings previously provided by the Customer to AEP and approved by AEP. These settings shall not be altered without the prior authorization of AEP.

13.7 Required Witness Tests

Before parallel operation with the Area EPS, and after completion of commissioning tests, additional witness testing and inspections may be required by AEP. The Customer is responsible for providing Qualified Personnel who will complete all required tests. Witness testing is generally required for larger DER. AEP reserves the right to require witness testing in all DER interconnected scenarios. Once witness testing is completed, the Customer shall provide AEP with all test results. Witness tests that must be performed in accordance with requirements described above include, but are not limited to:

- *Cease to energize* and trip test
- Open-phase Detection
- Anti-islanding
- Reconnection test
- Load Rejection Overvoltage test
- Power Limit functions test
- Radio Frequency Interference test
- Current harmonics test
- Telemetry/SCADA (If applicable)
- Primary Metering
- Direct Transfer Trip (If applicable)
- Reverse power relay (If applicable)
- Intentional Islanding testing (if applicable)

AEP reserves the right to require additional commissioning tests based on DER design evaluation results per *IEEE Std 1547™-2018* Clause 11.2.4.2.

13.8 Recommissioning

Recommissioning of a DER facility may be required by AEP at any point in the life of the DER facility.

AEP may request recommissioning of a DER facility for reasons including, but not limited to:

- Changes to DER facility components
- Changes in Operating Profile, protection or control settings, or other characteristics of the DER Facility
- Changes to Area EPS parameters
- Abnormal performance of the DER facility or customer complaints

AEP will inform the DER Customer of the need to perform DER recommissioning tests and determine the level of recommissioning tests required for a DER facility on a case-by-case basis.

13.9 Periodic Testing

Periodic testing may be required for DER connected to the Area EPS. AEP will inform the Customer during the interconnection process of any periodic testing requirements for the DER facility. In many instances this periodic testing may be performed remotely by AEP for the following purposes, including but not limited to, verification that communications connectivity remains in place and in effective operating order, verification of system settings and verification of the Operating Profile. In some instances, the DER Customer shall perform the required testing following the guidance specified in *IEEE Std 1547™-2018* Clause 11. Once testing is completed, the Customer shall provide AEP with all test results. Any insufficient results will need to be timely addressed by the Customer after notification of such by AEP.

AEP reserves the right to request the DER Customer perform testing on the DER facility at any point in the life of the DER facility. In such instances, AEP will provide adequate notice and will attempt to work with the Customer to minimize the disruption to normal operations.

Appendix A: Reference Standards and Guidelines

A.1 Industry Standards

- IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces, in *IEEE Std 1547-2018 (Revision of IEEE Std 1547-2003)*, vol., no., pp.1-138, 6 April 2018, doi: 10.1109/IEEESTD.2018.8332112
- Institute of Electrical and Electronics Engineers (IEEE) Standards *IEEE Std C37.90.2™ 18151453*
- American National Standards Institute (ANSI)
- Underwriter Laboratories (UL) 1741B

A.2 Federal Guidelines

- FERC Small Generator Interconnection Procedures (SGIP)

A.3 National Standards

- National Electric Code (NEC)
- North American Electric Reliability Corporation (NERC)
- National Fire Protection Association (NFPA)

A.4 Industry Association Guidelines

- Electric Power Research Institute (EPRI)
- International Electrotechnical Commission (IEC) 61000-4-3, 6100-3-7
- CBEMA and ITIC Requirements
- IREC Guidelines, Solar ABCs

A.5 Cyber Security Standards and Guidelines

- *IEEE Std 1547™-2018*
- IEC 62351 series
- International Organization for Standardization (ISO)/IEC 27000 series
- IEC 62443 series
- UL 2900-2 series
- National Institute of Standards and Technology Interagency or Internal Report (NISTIR) 7628

- National Institute of Standards and Technology (NIST) cybersecurity framework and other cybersecurity guidelines
- IEEE 1686 revision
- IEEE C37.240 revision
- Internet Engineering Task Force (IETF), Internet cybersecurity standards

A.6 AEP Standards

- Requirements for Connection of New Facilities or Changes to Existing Facilities Connected to the AEP Transmission System
- Guide for Electric Service and Meter Installations

Appendix B: Area EPS, Local EPS, PCC and PoC Exemplified

Examples of Area Electric Power System (Area EPS), Local Electric Power System (Local EPS), Point of Common Coupling (PCC) and Point of Connection (PoC) are shown in Figure 8. For details related to these concepts, reference *IEEE Std 1547™-2018 Figure 2*.

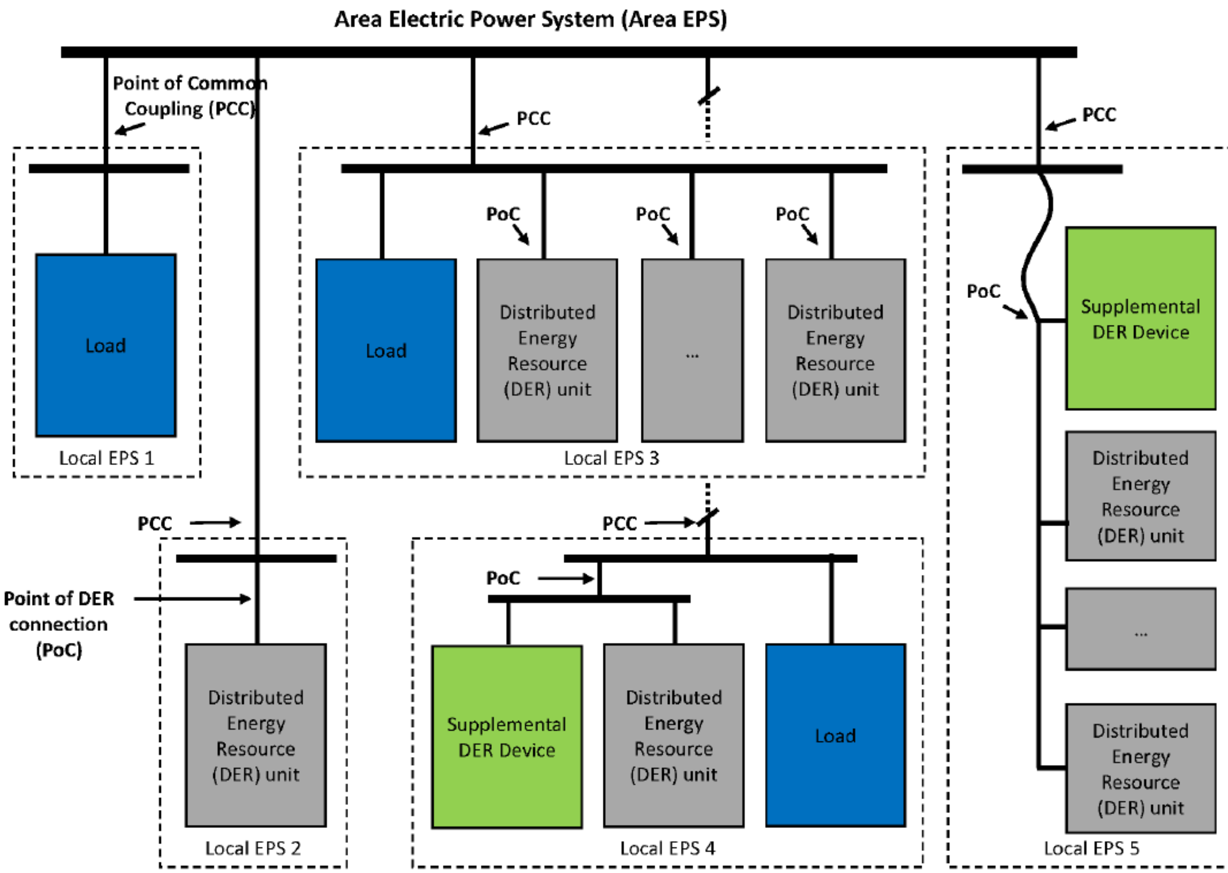


Figure 8. Area EPS, Local EPS, PCC and PoC Exemplified

Appendix C: Typical One-Line Diagrams

The following are AEP's requirements for one-line diagrams to be prepared by the Applicant and submitted to AEP as part of the DER application:

- All DER equipment must be identified and properly located on the one-line diagram.
  - Identification must include the manufacturer, model, and number of units.
- The Customer's name and address, in addition to the type and size of generator, is to be listed in a title block. If no address is available, include GPS coordinates of the Point of Common Coupling (PCC) and DER facility location.
- The AC disconnect switch is to be clearly labeled.
- If applicable, the one-line diagram must include the configuration details for any pre-existing DER facilities.
  - **Existing equipment must be labeled as such.**
- If the generator is less than 25 kW, a block diagram is acceptable.
- The nameplate ratings of kW capacity, voltage, amperage, and phase for the items must be shown.
- All transformer configurations (e.g., Grounded WYE-DELTA) and voltages must be listed.
- If the premise is a primary metered Customer, the one-line diagram must include all transformers from the PCC to the DER and, in addition, any other transformers operating in parallel with the DER behind the Customer's meter.
- For installations larger than 50 kW, the one-line diagram is to be signed and stamped by an applicable licensed Professional Engineer for the state in which the project is located.
- If known, the one-line diagram should include:
  - PCC to the power delivery system and phase identification.
  - Power Transformers – name or designation, nominal kVAR, nominal primary, secondary, tertiary voltages, vector diagram showing winding connections, tap settings, and transformer impedance. A copy of the transformer nameplate and test report that includes both positive and zero sequence impedance information will ultimately be required.
  - Instrument Transformers – voltage and current, phase connections.
  - Capacitor Banks – kVAR rating.
  - Circuit Breakers – interrupting rating, continuous rating, and operating times.
  - Fuses – manufacturer, type, size, speed, and location.

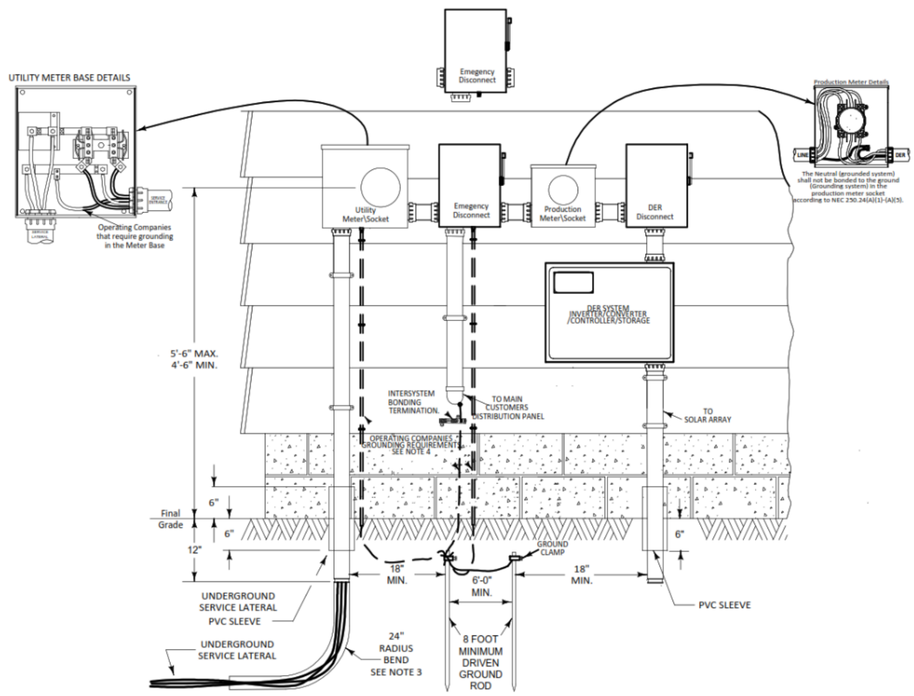
The following one-line diagrams are intended to be typical or representative samples of various types and sizes of generation facilities that are connected to and operate in parallel with the AEP power delivery system and do not purport to cover every possible case. Each site will have to be specifically designed considering the unique characteristics of each installation, the specific location of the Point of

Common Coupling and the operating and contractual requirements for that site. Additional ISO/RTO and NERC requirements may also apply.

- Residential DER with Storage
- Residential DER without Storage
- 5 MW DER at 34.5 kV
- 12 MW DER at 12 kV

Appendix D: Residential DER system with “Point of Connection Meter Details” and “Point of Common Coupling Meter Details”

AMERICAN ELECTRIC POWER COMPANY
METER STANDARDS



1.Application:

a.Customer shall apply for interconnection as detailed in AEP's TIIR, and provide all system specifications, one-line drawing before installing any DER equipment, and shall show proof of meeting Operating Company's adopted electrical code at time of commissioning.

b.Customer shall sign an Interconnection Service Agreement, and any necessary Purchase Power or Tariff Agreements.

c. Utilities shall install any production meters.

d. Any required telemetry equipment shall be installed as agreed upon within the Interconnection Service Agreement.

e. Customer is responsible for the installation and maintenance of all DER equipment and complying with all AHJ and NEC requirements and codes.

2. Production Meter base socket:

a. Customer will install the production meter socket with their DER system\systems. The production meter socket will be purchased by customer, except in areas where the Operating Company provide this component.

b. No additional equipment will be allowed to be installed inside the production meter base and wiring must be connected to the factory specified lugs inside meter base. Connection within the meter base shall only be done using manufacturer specified equipment.

c. Meter socket shall not be located in or over a walkway, driveway, or alley where susceptible to damage or hazardous to pedestrians

d. The production meter socket is required to follow all rules and requirements listed in the most recent version of the AEP Meter and Service Guide.

e. Production Meter socket must be installed outdoors in a readily accessible location. No trees or shrubs shall be planted in front of the meter.

f. Attach meter socket with metal or lead anchors only; plastic anchors are not acceptable

g. Utility will provide the billing and production meters which will be the utility's meters.

3. DER Disconnect:

a.Customer shall provide and install a readily accessible, visible-break isolation device that shall be located between the area EPS (Electrical Power System) and each DER for all installations.

b. AEP's full isolation service requirements can be found in section 4.9 of the company's technical interconnection interoperability requirements (TIIR) document found here (insert hyperlink to TIIR)

c. Installation must comply with all NEC, local codes and Authority having Jurisdiction

4. General Instructions:

a. Entrance and exit conduits shall be installed using the manufactures knockout holes

b. Area Clear of obstructions 15" on each side and 48" in front of meter.

c. The neutral shall not be bonded to the ground in the production meter socket.

d. The production meter socket shall be bonded . Installation must comply with all local codes, NEC and AHJ.

5. Completion and Inspection:

a. Once system has passed inspection and all the paperwork is completed, AEP will schedule a time to install a bi-directional billing meter and a production meter.

b. The system shall not be operated in parallel with the utilities grid until the "Permission to operate letter" has been received.

Notes:

1. The Neutral (grounded system) shall not be bonded to the ground (grounding system) in the production meter socket according to NEC article 250.24(A).
2. The Neutral (grounded system) shall be bonded to the ground (grounding systems) at the first means of attachment: disconnect, or meter base, as prescribed per Operating company and by NEC 250.24(A)
3. Operating Companies which requires a 36" radius bends in service entrance Conduits. APCo,
4. Grounding
   Grounding conductor not permitted in the meter socket per the following Operating company: APCo,

   Grounding conductor required in the meter socket only per the following Operating company: Texas

   Grounding conductor permitted in the meter base, disconnect, main distribution panel or as pre-scribed by the NEC 250.24(A): Ohio, I&M, SWEPCO,

Figure 9: DER Point of Connection Meter Details and Point of Common Coupling Meter Details