

**COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION**

In the Matter of:

Electronic Investigation Of Interconnection And Net)
Metering Guidelines) Case No. 2020-00302

**Kentucky Power Company’s Notice of Filing of Exhibits to
April 6, 2026 Supplemental Brief**

Kentucky Power Company (“Kentucky Power” or “Company”) files with the Public Service Commission of Kentucky Exhibits 1 and 2 to Kentucky Power’s April 6, 2026 Supplemental Brief in this matter. These exhibits were inadvertently omitted from that filing. The Company is filing these exhibits as soon as practical after the discovery of their omission.

Respectfully submitted,



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

Effective Date: 2/1/2026

Revision: 2.0

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

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Revision History

Rev.	Description of Change(s)	By	Approved Date	Effective Date
0	Original Issue	AEP	8/25/2023	1/1/2024
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	1/1/2024
0.2	Figure corrections.	AEP	12/28/2023	1/1/2024
0.3	Updated Thermal Impact Limits in Section 9.3 and performed other minor updates and corrections.	AEP	1/29/2024	2/1/2024
1.0	Annual update to original document.	AEP	12/19/2024	2/1/2025
2.0	Annual update.	AEP	12/19/2025	2/1/2026



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1.0 Introduction

1.1 Purpose

This DER Technical Interconnection and Interoperability Requirements (TIIR) document specifies the technical requirements for the interconnection of Distributed Energy Resources (DERs) to AEP's distribution system. In some instances, additional Transmission system or RTO requirements may also be applicable (see Section [12.6](#)).

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.

1.2 Scope and Applicability

The requirements specified in this document apply to all DER Facilities as defined in Section [2.0](#) of this document that require an interconnection service agreement and are connected to AEP's distribution system. 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.

The requirements specified in this document do not apply to, and an interconnection service agreement is not required, for:

- Electric vehicles (EV) that operate solely as a load, or in other words, EVs that are unidirectional (known as V1G) and thus, can only charge and could never discharge to the grid or any onsite loads.
- Backup power systems, including Energy Storage Systems, that are designed and tested to only operate when the premise is not connected to the AEP Area EPS.

Note: This TIIR document includes some summary statements related to external industry standards. If there is a conflict between the summary statements in this document and the full text of the external standards, the external standards shall prevail when referenced.

Note: 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 document.



1.3 Adoption of IEEE Std 1547™-2018

AEP has adopted *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) "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>.

1.4 Effective Date, Grandfathering Clause, and Material Modification

The requirements specified in this document shall apply as of the effective date of this document to new DER interconnection request applications based on their received date. For applications requiring a system impact study, the requirements in effect on the date that the Study Agreement is signed, and the Study fee or deposit is paid will apply.

For DER applications submitted to AEP since the original TIIR document took effect January 1, 2024, inverters shall be:

- UL 1741 SB, or equivalent standards, certified as "Grid Support Interactive Inverter" or "Grid Support Utility Interactive Inverter" by a testing agency currently listed as a Nationally Recognized Testing Laboratory (NRTL) by the US Department of Labor Occupations Safety and Health Administration (OSHA), 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.

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>



Any DER interconnection applications that have been received prior to the Effective date of this document are deemed “grandfathered” in by AEP and may continue to meet the interconnection requirements in effect at the time of the application receipt.

Existing DER interconnection applications that have undergone or in the process of making a *material modification* after 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 materially impacts the cost, timing, or design of any customer interconnection facilities or Area EPS 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.

Note: When a customer is expanding or modifying an existing DER Facility, the new requirements will apply to new additions such as additional or replacement inverters according to the grandfathering rules, not the entirety of pre-existing equipment.

For the state of Virginia, "Material modification" has the meaning ascribed to it in 20VAC5-314-39.

For DER applicants connecting to the AEP system in other states, 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 [1.5.1](#)).
- 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 the maximum nameplate capacity of the DER facility, even when self-limited.
- Amends the location of the DER site Point of Common Coupling or otherwise changes eligibility for interconnect to the requested company.
- Requires the removal or retirement of any DER equipment.



Customers shall communicate all proposed DER changes to AEP for review via a submission through its online DER interconnection application system. AEP will determine if any modification constitutes a *material modification* per this TIIR document or state-specific requirements.

Note: 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.

1.5 Responsibilities

1.5.1 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 State and local codes, standards, statutes, and commission orders.

1.5.2 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.

1.5.3 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

Terms used in this document and their use are 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 <i>TIIR</i> Appendix B and <i>IEEE Std 1547™-2018 Figure 2</i>).
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 <i>IEEE Std 1547™-2018 Clause 3.1</i>).
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
Backup Power System		A backup power system is intended to provide power to local load only during loss of connection to the Area EPS. The DER associated with a backup power system may utilize a momentary make-before-break operation to return the load to the Area EPS provided the duration of paralleling the sources is less than 100ms.
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: <ul style="list-style-type: none"> • Receives delivery service • Supplies electric service • Combines electric supply and delivery service
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 <i>IEEE Std 1547™-2018</i> 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.



Term	Acronym	Definition
Electric Power Research Institute	EPRI	The Electric Power Research Institute, Inc. (epri.com) is an independent, nonprofit organization that conducts research 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 <i>IEEE Std 1547™-2018 Figure 2</i>).
Express Feeder		A distribution feeder that is initially constructed between a substation and a customer’s PCC to provide service to a DER. It may serve one or more customers after its initial construction.
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.
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 <i>IEEE Std 1547™-2018</i>)
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 (<i>IEEE Std 1547™-2018</i>).
Local Electric Power System	Local EPS	An EPS contained entirely within a single premise or group of premises (Reference <i>TIIR Appendix B and IEEE Std 1547™-2018 Figure 2</i>).



Term	Acronym	Definition
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 1.4 .
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		<p>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.</p> <p>For DERs: means the sum total of maximum rated power output of all a DER’s constituent generating units and energy storage units as identified on the manufacturer nameplate, regardless of whether it is limited by any approved means.</p>
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 Common Coupling and the resource characteristics, e.g., solar output profile or Energy Storage System operation.
Parallel Operation		Means the operation, for 100 milliseconds or longer, of a DER while connected to the energized distribution system.
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 <i>TIIR</i> Appendix B and <i>IEEE Std 1547™-2018 Figure 2</i>).
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 <i>IEEE Std 1547™-2018</i> exclusive of any load present in the respective part of the Local EPS (Reference <i>TIIR</i> Appendix B and <i>IEEE Std 1547™-2018 Figure 2</i>).
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 <i>IEEE Std 1547™-2018</i> . DER requirements of this <i>TIIR</i> apply to the RPA located at the PCC in all circumstances.
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.
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.



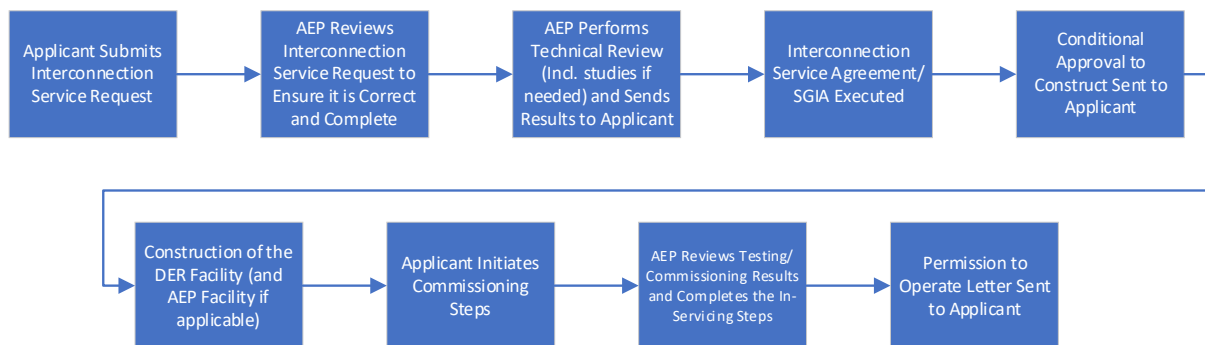
Term	Acronym	Definition
Supervisory Control and Data Acquisition	SCADA	A tool used by dispatchers to monitor system conditions, as well as perform limited remote substation functions such as opening/closing a breaker.
Supplemental DER Device		Any Customer-owned equipment that is used to obtain compliance with some or all of the requirements of this TIIR (Reference <i>TIIR</i> Appendix B and <i>IEEE Std 1547™-2018 Figure 2</i>).
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](#).

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 an automated technical assessment. Many applications will continue to 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 with 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 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 Customer. This contract includes details of the relevant conditions described and approved by the Applicant. Upon execution of the interconnection agreement by the Customer and AEP, construction of the Customer's DER Facility may begin. 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 all contractual obligations identified in the application process and interconnection agreement being met.

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 construction of the DER Facility, construction of utility upgrades, and installation verification of the DER Facility, 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 required DER testing and/or test the DER at the time of installation or any point in the life of the DER facility.

It is possible that the technical review will yield results that indicate there is no path forward for the desired interconnection. In these cases, an application will be withdrawn. It is also possible that the



required mitigations are deemed undesirable by the applicant and in such cases the application will be withdrawn.

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

In addition to the requirements of Section 1.3 and 1.4 of this document, 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 1](#) below.

Table 1: 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 Express Feeder Requirement

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

4.3 Transformer Configuration Requirements

This section defines the requirements for allowable transformer winding configurations to interface DER to the four-wire grounded-wye Distribution System Primary or three-wire delta 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. [Figure 2](#) and [Figure 3](#) are provided to aid in identifying applicable transformers. Additional evaluation will be required if additional transformers are installed in the Customer’s facility and are connected to the same local EPS as the DER equipment.

Figure 2: Applicable Transformers – Example 1

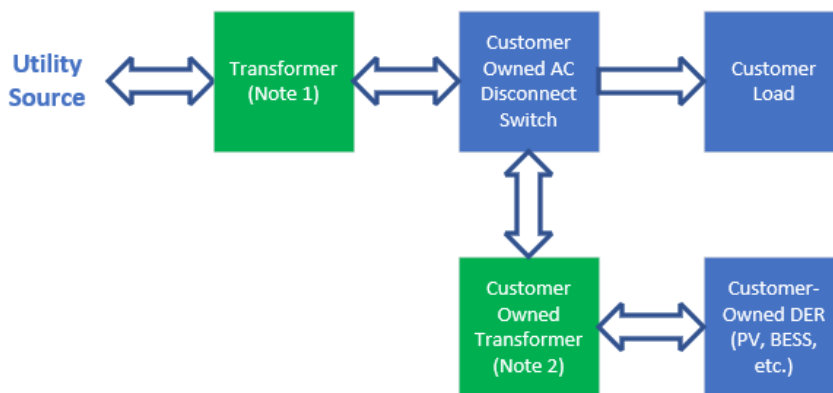
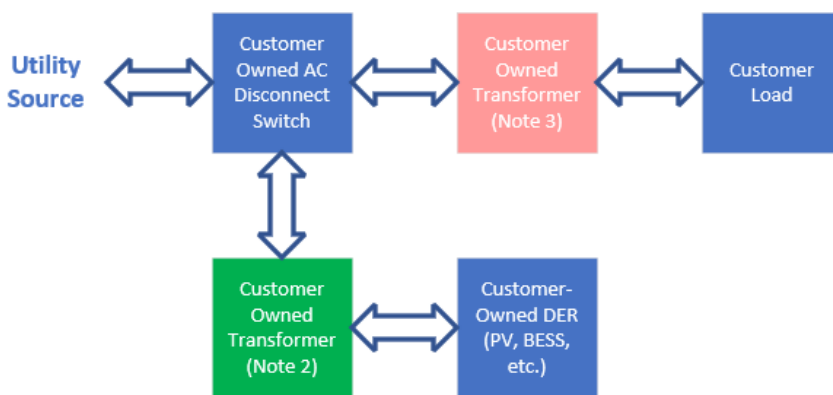


Figure 3: Applicable Transformers – Example 2



Note 1: Section 4.3 is applicable in its entirety, regardless of whether the transformer is AEP-owned or Customer-owned.

Note 2: Section 4.3 is applicable in its entirety.

Note 3: Section 4.3 is not applicable.



Note: 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.

AEP requires that any DER Facility, that is not collocated with residential, commercial, or industrial site load, own and operate their own DER interconnection transformer and be primary metered at the distribution system primary voltage.

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 Acceptable Transformer Winding Configurations for Three-Phase DER

The following three-phase transformer-winding configurations, shown in [Table 2](#) 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), or between AEP’s or three-wire delta Distribution System Primary (Primary) and a three-phase DER Facility (Secondary) pending results of an appropriate screen or study.

All three-phase DER Facilities shall have a distribution primary ground source configuration that cannot be separated from the DER while the DER is providing capacity to the primary distribution system.

Table 2: Acceptable Transformer Winding Configurations for Three-Phase DER

Meter Type	AEP’s Distribution System Primary	AEP-Owned Transformer	Customer-Owned Transformer Primary-Utility / Secondary-Customer
Primary (typically metered at medium voltage)	Gd-Wye*	n/a	Gd-Wye / Gd-Wye
		n/a	Gd-Wye / Delta
Secondary (typically metered at low voltage)	Gd-Wye*	Gd-Wye / Gd-Wye	Gd-Wye / Gd-Wye or Gd-Wye / Delta

*In rare cases where the AEP distribution system primary is a delta configuration, then transformers with a primary-utility side delta configuration are acceptable. AEP will work with the customer on these unique occurrences.



4.3.2 Acceptable Transformer Winding Configurations for Single-Phase DER

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

Table 3: Acceptable Transformer Winding Configurations for Single-Phase DER

Meter Type	AEP’s Distribution System Primary	AEP-Owned Transformer Primary-Utility / Secondary-Customer
Secondary (typically metered at low voltage)	Gd-Wye*	Single-Phase / Split-Phase
		Gd-Wye / Gd-Wye
		Gd-Wye / Open Delta

*In rare cases where the AEP distribution system primary is a delta configuration, then transformers with a primary-utility side delta configuration are acceptable. AEP will work with the customer on these unique occurrences.

4.3.3 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.
- Single-phase DER Facilities may be permitted to connect to an open-delta service transformer, pending results of an appropriate screen or study. Multi-phase DER Facilities are not permitted to connect to an open-delta service transformer configuration.
- Three-phase DERs may only be connected to three-phase points of common coupling through an acceptable three-phase transformer winding configuration, per this TIIR document.

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 directly (via electronic means) or indirectly (via operator-operator communications). 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/load during real time operations by leveraging these functions to address operational emergencies or constraints. AEP may issue these commands directly (via electronic means) or indirectly (via operator-operator communications).

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 all DER Facilities.

- AEP standards require a single isolation device between the Area EPS and all DER Facilities at a customer's premise. This is to allow the company to isolate all DER Facilities with a single operation.
 - Exceptions to the single isolation device standard are at the discretion of the Area EPS Operator and require prior approval. Exceptions will only be considered following a written request from the Professional Engineer, who signed and stamped the one-line diagram, stating the necessity for multiple isolation devices.
 - Where exceptions to the single isolation device standard are granted, each isolation device must be clearly labeled on the one-line diagram and at the physical installation as "Utility ACD x of y" where y is the total number of isolation devices.



- The isolation device shall be installed in addition to any other disconnect type devices that may be required by other applicable codes or standards.
- In a load-side connection, the isolation device may be required by the Area EPS Operator to be properly fused for the size (ampacity) of the wires, or to be non-fused when the disconnect is not intended to provide overcurrent protection. In a supply-side connection, the isolation device shall be properly fused in accordance with all applicable laws, statutes, guidelines, and regulations.

Note: AEP strongly encourages all customers to ensure that their important loads are not electrically behind the DER isolation switch so that the load can continue to be served by AEP even when the DERs must be isolated by opening this switch.

- AEP standards require that the 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 identifies the DER Disconnect Switch which will isolate energized equipment from the utility grid. [Figure 4](#), [Figure 5](#), and [Figure 6](#) below are presented as examples for consideration.
 - Exceptions to the standard location for the isolation device requires prior approval by the Area EPS Operator and will only be considered following a written request stating the necessity for an exception.
 - If the Area EPS Operator approves an exception for the location of the disconnect, a permanent plaque must be placed next to the existing meter clearly stating the location of the isolation device at the premise.

Figure 4: Sample Labeling

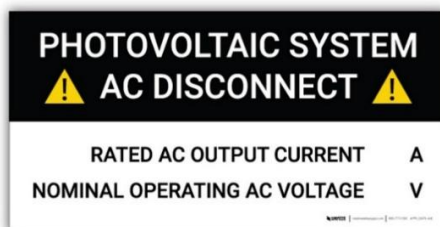


Figure 5: Sample Labeling

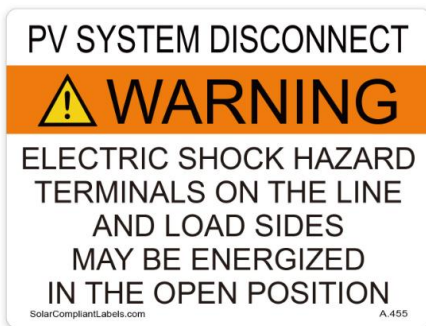


Figure 6: Sample Labeling



- 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.
- A circuit breaker may serve as an appropriate manual isolation device in some installations provided it satisfies the requirements of being readily accessible, lockable, and providing a visible-break and is located between the Area EPS and the DER.

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 residential, commercial or industrial site load, 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 residential, commercial, or industrial site load, 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 4](#) below.

Table 4: 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
Permit Service		ES_PERMIT_SERVICE-SS	Mode	Enabled
Enter Service Voltage	ES Voltage Low Setting	ES_V_LOW-SS	V p.u.	0.917
	ES Voltage High Setting	ES_V_HIGH-SS	V p.u.	1.05
Enter Service Frequency	ES Frequency Low Setting	ES_F_LOW-SS	Hz	59.5
	ES Frequency High Setting	ES_F_HIGH-SS	Hz	60.1
Soft-Start Ramp	ES Randomized Delay	ES_RANDOMIZED_DELAY-SS	s	300
	ES Delay Setting	ES_DELAY-SS	s	300
	ES Ramp Rate Setting	ES_RAMP_RATE-SS	s	300



4.13 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 5 below).

Table 5: 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.

4.15 DER Self-Limiting Output

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 self-limiting output.

AEP will allow the following methods for self-limiting output (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 be designed with a Nationally Recognized Testing Laboratory (NRTL) certified Power Control System, 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.

Note: A DER Facility's self-limited values will be used for purposes of technical analysis and review of screening questions unless state-specific rules dictate the use of nameplate ratings. A DER Facility's nameplate rating is used for state level determination and tariff eligibility.



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 6](#) 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 6: 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	Mutual Agreement
Induction generator	Hydro	Mutual Agreement
Hybrid	Combination / Multiple Types	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 and following the DER Categories defined in [Table 6](#) above, AEP requires the default settings shown in

[Table 7](#), [Table 8](#), and [Table 9](#) below be applied to connected Category B DER, and the default settings shown in [Table 10](#) below be applied to connected Category B 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 7: Reactive Power Control Settings – Constant Power Factor Mode

CONSTANT POWER FACTOR MODE (Specified Power Factor)	Standard Parameter Root Label (based on 1547.1 and modified by EPRI)	UNITS	Utility- Required Setting
Constant Power Factor Mode	CONST_PF_MODE_ENABLE-SS	Mode	Enabled
Constant Power Factor Excitation	CONST_PF_EXCITATION-SS	Mode	INJ
Constant Power Factor setting	CONST_PF-SS	PF	1

Table 8: Reactive Power Control Settings - Constant Reactive Power Mode

CONSTANT REACTIVE POWER MODE	Standard Parameter Root Label (based on 1547.1 and modified by EPRI)	UNITS	Utility- Required Setting
Constant Reactive Power Mode Enable	CONST_Q_MODE_ENABLE-SS	Mode	Disabled
Constant Reactive power setting	CONST_Q-SS	% S	0

Table 9: Reactive Power Control Settings - Volt-Reactive Power Mode

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
Voltage-Reactive Power Mode Enable		QV_MODE_ENABLE-SS	Mode	Disabled
Near Nominal	Vref	QV_VREF-SS	V p.u.	1.00
	Autonomous Vref Adjustment Enable	QV_VREF_AUTO_MODE-SS	Mode	Disabled
	Vref adjustment time Constant	QV_VREF_OLRT-SS	s	-
Point 2	V/Q Curve Point V2 Setting	QV_CURVE_V2-SS	V p.u.	0.980
	V/Q Curve Point Q2 Setting	QV_CURVE_Q2-SS	Q p.u.	0.00
Point 3	V/Q Curve Point V3 Setting	QV_CURVE_V3-SS	V p.u.	1.020
	V/Q Curve Point Q3 Setting	QV_CURVE_Q3-SS	Q p.u.	0.00
Point 1	V/Q Curve Point V1 Setting	QV_CURVE_V1-SS	V p.u.	0.92



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
	V/Q Curve Point Q1 Setting	QV_CURVE_Q1-SS	Q p.u.	0.44
Point 4	V/Q Curve Point V4 Setting	QV_CURVE_V4-SS	V p.u.	1.08
	V/Q Curve Point Q4 Setting	QV_CURVE_Q4-SS	Q p.u.	-0.44
QV Open Loop Response Time Setting		QV_OLRT-SS	s	5

Table 10: Reactive Power Control Settings - Active Power-Reactive Power Mode

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
Active Power Reactive Power Mode Enable		QP_MODE_ENABLE-SS	Mode	Disabled
Active Power, Generation	P-Q curve P3 Setting	QP_CURVE_P3_GEN-SS	P p.u.	1.00
	P-Q curve P2P-Q Setting	QP_CURVE_P2_GEN-SS	P p.u.	0.50
	P-Q curve P1 Setting	QP_CURVE_P1_GEN-SS	P p.u.	0.20
Active Power, Absorption	P-Q curve P3 Setting	QP_CURVE_P1_LOAD-SS	P p.u.	-0.20
	P-Q curve P3 Setting	QP_CURVE_P2_LOAD-SS	P p.u.	-0.50
	P-Q curve P3 Setting	QP_CURVE_P3_LOAD-SS	P p.u.	-1.00
Reactive Power, Generation	P-Q curve P3 Setting	QP_CURVE_Q3_GEN-SS	S p.u.	-0.44
	P-Q curve P3 Setting	QP_CURVE_Q2_GEN-SS	Q p.u.	0.00
	P-Q curve P3 Setting	QP_CURVE_Q1_GEN-SS	Q p.u.	0.00
Reactive Power, Absorption	P-Q curve P3 Setting	QP_CURVE_Q1_LOAD-SS	Q p.u.	0.00
	P-Q curve P3 Setting	QP_CURVE_Q2_LOAD-SS	Q p.u.	0.00
	P-Q curve P3 Setting	QP_CURVE_Q3_LOAD-SS	S p.u.	0.44



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 and following the DER Categories defined in [Table 6](#) above, AEP requires the default settings shown in [Table 11](#) below be applied to connected Category B 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 11: 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
Voltage-Active Power Mode Enable		PV_MODE_ENABLE-SS	Mode	Disabled
Point 1	PV Curve Point V1 Setting	PV_CURVE_V1-SS	V p.u.	1.06
	PV Curve Point P1 Setting	PV_CURVE_P1-SS	P p.u.	1.00
Point 2	PV Curve Point V2 Setting	PV_CURVE_V2-SS	V p.u.	1.10
	PV Curve Point P2 gen Setting	PV_CURVE_P2_GEN-SS	P p.u.	Pmin
	PV Curve Point P'2 load Setting	PV_CURVE_P2_LOAD-SS	P p.u.	0.00
P(V) Open Loop Response Time Setting		PV_OLRT-SS	s	10



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 12](#) below.

Table 12: 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 Amendment⁵

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.

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

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



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 13](#), [Table 14](#), and [Table 15](#) 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 or at the Customer’s request, with AEP’s approval, to comply with specific RTO requirements. All site-specific settings shall be documented in the interconnection agreement. AEP reserves the right to change the voltage ride-through capability requirements and trip settings.

Table 13: 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	Utility- Required Setting
OV2	HV Trip Curve Point OV2 Setting	OV2_TRIP_V-SS	V p.u.	1.20
	HV Trip Curve Point OV2 Setting	OV2_TRIP_T-SS	s	0.16
OV1	HV Trip Curve Point OV1 Setting	OV1_TRIP_V-SS	V p.u.	1.10
	HV Trip Curve Point OV1 Setting	OV1_TRIP_T-SS	s	2.0
UV1	LV Curve Trip Point UV1 Setting	UV1_TRIP_V-SS	V p.u.	0.70
	LV Curve Trip Point UV1 Setting	UV1_TRIP_T-SS	s	2.0
UV2	LV Curve Trip Point UV2 Setting	UV2_TRIP_V-SS	V p.u.	0.45
	LV Curve Trip Point UV2 Setting	UV2_TRIP_T-SS	s	0.16



Table 14: 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	Utility- Required Setting
OV2	HV Trip Curve Point OV2 Setting	OV2_TRIP_V-SS	V p.u.	1.20
	HV Trip Curve Point OV2 Setting	OV2_TRIP_T-SS	s	0.16
OV1	HV Trip Curve Point OV1 Setting	OV1_TRIP_V-SS	V p.u.	1.10
	HV Trip Curve Point OV1 Setting	OV1_TRIP_T-SS	s	2.0
UV1	LV Curve Trip Point UV1 Setting	UV1_TRIP_V-SS	V p.u.	0.70
	LV Curve Trip Point UV1 Setting	UV1_TRIP_T-SS	s	10.0
UV2	LV Curve Trip Point UV2 Setting	UV2_TRIP_V-SS	V p.u.	0.45
	LV Curve Trip Point UV2 Setting	UV2_TRIP_T-SS	s	0.16

Table 15: 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	Utility- Required Setting
OV2	HV Trip Curve Point OV2 Setting	OV2_TRIP_V-SS	V p.u.	1.20
	HV Trip Curve Point OV2 Setting	OV2_TRIP_T-SS	S	0.16
OV1	HV Trip Curve Point OV1 Setting	OV1_TRIP_V-SS	V p.u.	1.10
	HV Trip Curve Point OV1 Setting	OV1_TRIP_T-SS	S	13.0
UV1	LV Curve Trip Point UV1 Setting	UV1_TRIP_V-SS	V p.u.	0.88
	LV Curve Trip Point UV1 Setting	UV1_TRIP_T-SS	S	21.0
UV2	LV Curve Trip Point UV2 Setting	UV2_TRIP_V-SS	V p.u.	0.50
	LV Curve Trip Point UV2 Setting	UV2_TRIP_T-SS	S	2.00



6.5 Frequency Ride-Through Capability Requirements and Trip Settings

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 16](#) 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 or at the Customer’s request, with AEP’s approval, to comply with specific RTO requirements. All site-specific settings shall be documented in the interconnection agreement. AEP reserves the right to change these DER frequency trip settings.

Table 16: AEP-Required Abnormal DER Frequency Trip Settings

Shall Trip Function	Utility Required 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.

Depending on the DER abnormal operating performance category (Category I, II or III), the DER shall have the capability of mandatory operation with frequency-droop (frequency-power) as specified in [Table 17](#) below.

Table 17: AEP-Required Parameters of frequency-droop (frequency-power) operation for DERs

Parameter	Utility Required Settings			Ranges of Allowable Settings		
	Category I	Category II	Category III	Category I	Category II	Category III
db_{OF}, db_{UF} (Hz)	0.036	0.036	0.036	0.017 ^b -1.0	0.017 ^b -1.0	0.017 ^b -1.0
k_{OF}, k_{UF}	0.05	0.05	0.05	0.03-0.05	0.03-0.05	0.02-0.05
T_{response} (small signal) (s)	5	5	5	1-10	1-10	0.2-10

^b A deadband of less than 0.017 Hz shall be permitted



Reference Terms:

- Overfrequency Droop (dbOF): Frequency droop deadband for overfrequency conditions
- Underfrequency Droop (dbUF): Frequency droop deadband for underfrequency conditions
- Overfrequency Droop (kOF) : Frequency droop per-unit frequency change for overfrequency conditions corresponding to 1 per-unit power output change
- Underfrequency Droop (kUF) : Frequency droop per-unit frequency change for underfrequency conditions corresponding to 1 per-unit power output change
- Open Loop Response Time: The duration from a step change in control signal input until the output changes by 90% of its final change, before any overshoot



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](#).

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 Facilities 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 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 to 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 DER Facility shall meet critical fault clearing times to ensure its stability.

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.

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 1.4 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. If a DER is determined to reach or exceed any of the limits captured in Sections [8.1](#) through [8.3](#), either during the interconnection process or after the DER has been put in-service, mitigation shall be required.

The Customer shall provide, at AEP's request, evidence confirming the capability of installed DER equipment to satisfy 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 18* 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 18: Minimum Individual DER Flicker Emission Limits^a

E_{Pst}	E_{Plt}
0.35	0.25

^a95% 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 19](#) and [Table 20](#) below).

Table 19: Maximum Odd Harmonic Current Distortion in Percent of Rated Current (I_{rated})^a

Individual odd harmonic order h	$h < 11$	$11 \leq h < 17$	$17 \leq h < 23$	$23 \leq h < 35$	$35 \leq h < 50$	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 20: Maximum Even Harmonic Current Distortion in Percent of Rated Current (I_{rated})^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 [IEEE Std 1547™-2018] Table 18

^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

AEP requires that all voltage regulation controls between the PCC and the transmission source be capable of and programmed to operate in Co-Gen mode for any DER Facility with a total nameplate capacity of 500 kW or larger that is not collocated with residential, commercial or industrial site load.



9.0 Grid Integration Requirements for DER Interconnecting to Radial Distribution Systems

9.1 General Requirements

AEP's integration requirements for DERs interconnecting to radial distribution systems 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 9.8, mitigation shall be required. The mitigation 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 21](#) below documents the operating limits established by AEP for steady state voltage during normal or contingency conditions.



Table 21: 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) and the Upper Voltage Boundary in rural areas to be set at 129 V (on a 120 V base).

9.3 Thermal Impact Limits

All thermal ratings considered shall be based on unbalanced load conditions.

9.3.1 Protective Device Limits

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.

9.3.2 Station Transformer Limits

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

9.3.3 Distribution Line Transformer Limits

Distribution line transformers include service transformers and primary step-down transformers. Distribution line transformer loading shall be limited to no greater than the nameplate kVA rating when operating in a reverse power flow direction.

9.3.4 Distribution Feeder Limits

Table 22: 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%



9.3.5 Distribution Voltage Regulator Limits

Table 23: 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) 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 the PCC or substation bus, 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.

When the Area EPS Operator must operate in abnormal conditions for any reason, the Area EPS Operator may disconnect DERs connected in the impacted area of the grid if the grid impact by the DER is unknown or unstudied for the conditions that exist during this time. This includes DER that interconnects to a feeder or substation bus to which additional load is transferred during manual or automated switching operations, such as during the operation of Distribution Automation schemes or DERs interconnected to an area of the grid that has had equipment that is normally operating taken out of service due to failure or otherwise.

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 Area EPS 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 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 6](#) 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 to any applicable contractual or tariff-based reactive power or power factor requirements when the DER Facility becomes operational. AEP reserves the right to request or implement power factor performance adjustments for all connected DER.

9.9 DER Ramp Rate

AEP reserves the right to require a defined ramp up/down rate (kW/sec) for normal DER Operation. This ramp rate may be utilized to mitigate criteria violations to encourage positive study results and compatibility of the DER with the AEP system. Any such requirement will be noted in the Technical Review Results and should be a stipulation of any related Interconnection Service Agreement.



10.0 Grid Integration for DER Interconnecting to Distribution Network Systems

DER interconnecting to distribution network systems must comply with all requirements of this TIIR. This section will reference *IEEE Std 1547™-2018* Clause 9 as it relates specifically to DER on distribution secondary grid and spot networks and discusses additional AEP requirements for DER interconnection onto a networked distribution 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, when connected to a network, DER Facilities using an automatic transfer scheme in which load is transferred between the DER and the EPS in a momentary (less than 100 ms) 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, a signal sent by the Area EPS Operator, and indirect communications (phone calls, e-mails, etc.).

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. AEP will work with the DER Customer to engineer, design, and implement any required telemetry following execution of the interconnection agreement.

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 Facilities at or above 500 kW Nameplate Capacity

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 Facility 500 kW or larger for monitoring and control purposes.

11.1.2 Requirements for DER Facilities at or above 200 kW and less than 500 kW Nameplate Capacity

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 Facilities under 500 kW.

11.1.3 Requirements for DER Facilities less than 200 kW Nameplate Capacity

All DER Facilities 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 Requirements for all DER Facilities

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 Facilities 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 24* below).

Table 24: 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 <i>Section 5.2 of IEEE 1547-2018</i>
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 <i>Section 5.2 of IEEE 1547-2018</i>
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 <i>Section 1.4 of IEEE 1547-2018</i>)
Abnormal operating performance category	Indication of voltage and frequency ride-through capability Category I, II, or III, as described in <i>Section 1.4 of IEEE 1547-2018</i>
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



Parameter	Description
AC voltage nominal rating	Nominal AC voltage rating in RMS volts
AC voltage maximum rating	Maximum AC voltage rating in RMS volts
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 <i>cease to energize</i> and trip state	Reactive susceptance that remains connected to the Area EPS in the <i>cease to energize</i> 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 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 25 below). The information shall be the latest value that has been measured within the required response time.



Table 25: 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
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.

AEP requires MESA-DER (IEEE 1815.2) compliance with BESS installations.

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 a 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 revenue metering for each DER Facility 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.

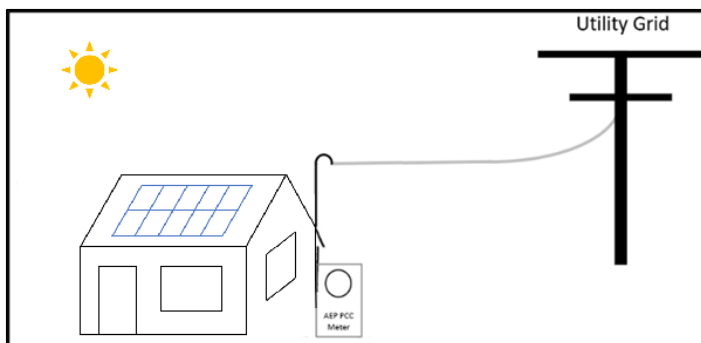
Ultimately, multiple questions will need to be addressed or answered by the Customer to determine the required metering configuration, including:

- 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?
- What telemetry requirements apply?
- What are the technical characteristics, such as size, of the DER Facility?
- What primary metering (voltage and current transformers) or secondary metering equipment (current transformers) is needed?
- 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:

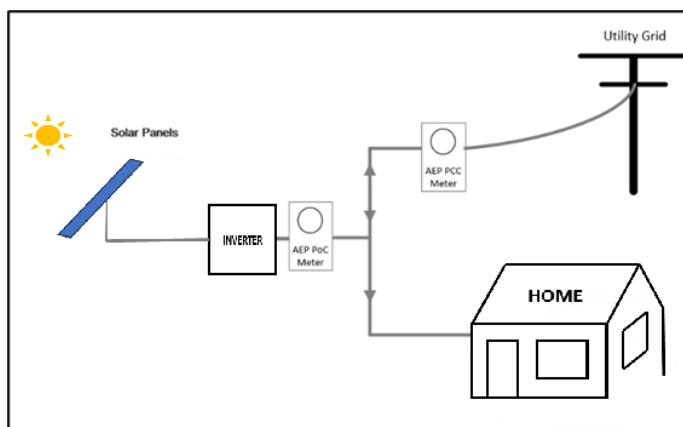
- Residential Customer:
 - Single-metered DER: installations will use a bidirectional PCC Meter that will be programmed to register and record energy delivered to the Customer from the utility as well as any excess generation that the Customer puts back onto the Area EPS. These values will be recorded in separate channels of the meter.

Figure 7: Representative Illustration of a Single-Metered DER Configuration for a Residential Customer



- 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. The PoC meter will only be required if the state tariff allows it. See [Table 27](#) for additional details.

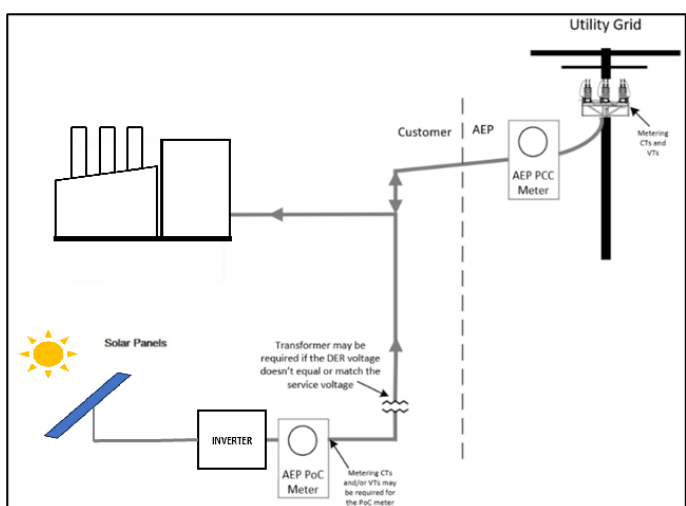
Figure 8: Representative Illustration of a Multi-Metered DER Configuration for a Residential Customer



- Commercial/Industrial Customer without Metering CT or VT Service: installations will have the same metering requirements like a Residential customer and will fall under either Single-metered DER or Multi-metered DER configuration depending on the state tariff. See [Table 27](#) for additional details.
- Commercial/Industrial Customer with Metering CT or VT Service:
 - Installations will fall under Single-metered DER or Multi-metered DER configuration depending on the state tariff.
 - Metering CTs shall have a high accuracy, extended range, 0.15% accuracy class or better, and 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.

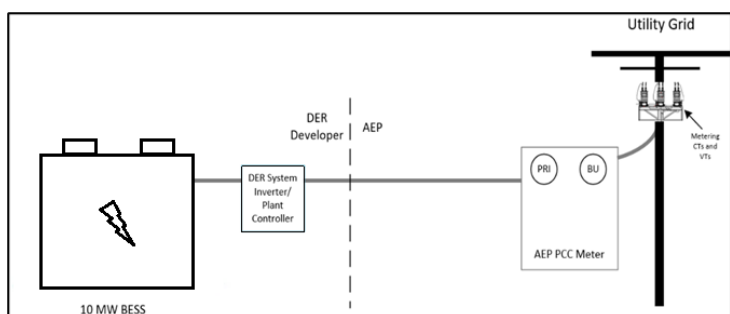
- If an existing customer proposes a DER, then the existing PCC metering CT and VT will need to be evaluated to make sure that the existing metering CT and VT can accurately capture the customer’s load scenarios (light load, peak load, and normal load when the DER Facility is generating at full capacity). If it’s determined that the existing metering CT or VT accuracy is less accurate than the 0.15% accuracy range, then the metering CT or VT will need to be upgraded. In some cases, the PCC revenue meter may also need to be upgraded to meet AEP’s latest metering standard.
- If the state tariff allows a PoC meter, then depending on the customer’s design, metering CTs and/or VTs may be required.

Figure 9: Representative Illustration of a Multi-Metered DER Configuration for a Commercial/Industrial Customer with metering CT and VT service



- RTO’s Wholesale Market Participant DER: Small scale standalone generator (10 MW or less) with the intent to participate in RTO’s wholesale market. Typically, these DERs require CT and VT metering service. Metering CTs shall have a high accuracy, extended range, 0.15% accuracy class or better, and 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. AEP uses Primary and Backup meters for the PCC meter. These meters are Distributed Network Protocol (DNP) capable.

Figure 10: Representative Illustration of a Single-Metered DER Configuration for a standalone generator



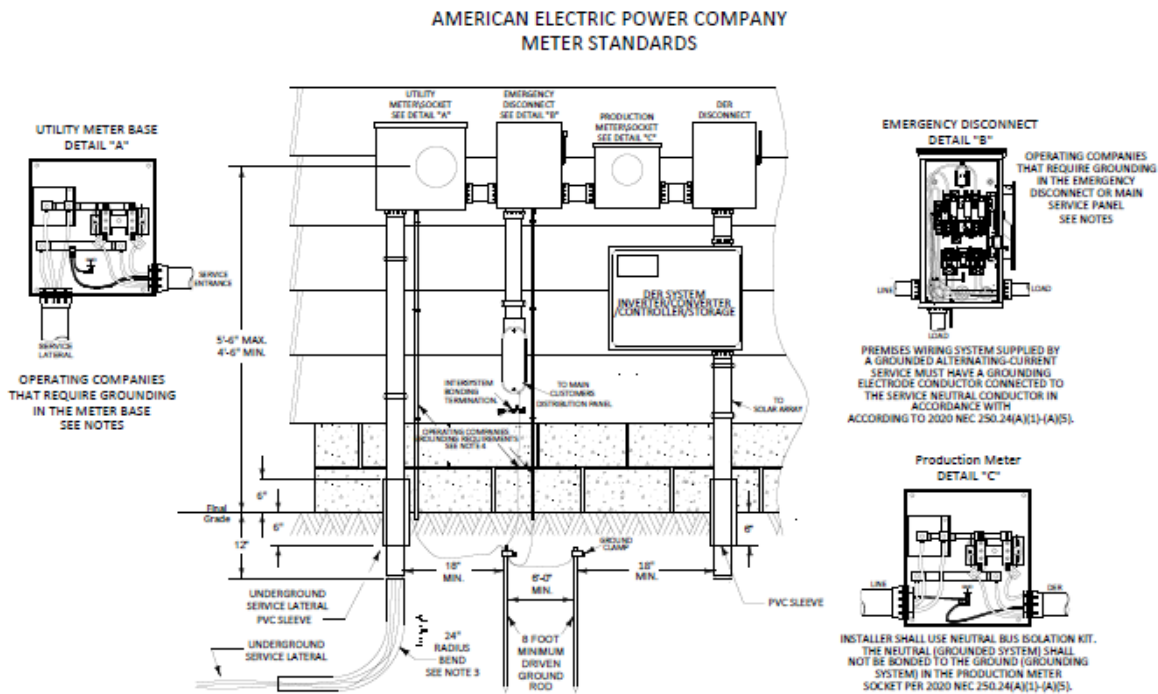


12.2 DER Meter Placement for Residential Installations

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.

Figure 11 below represents AEP’s standard Residential DER Metering installation for a multi-metered DER Facility. Please review [Appendix D](#) for some additional detailed notes for installation guidance. Additional details on AEP’s general facility metering requirements can be found in AEP’s Meter and Service Guide, available by clicking the link in the upper right at: [Requirements For Electrical Service \(aepnationalcustomers.com\)](#)

Figure 11: DER Metering Installation Diagram for a Residential Multi-Metered DER



12.3 Meter Socket Collar Devices

The following [Table 26](#) 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. 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 26: Allowed Meter Collars for DER installations.

Operating Companies that <i>Allow</i> Meter Collars for DER installations	Operating Companies that <i>Do Not Allow</i> Meter Collars for DER installations
Appalachian Power	AEP Ohio
	AEP Texas
	Indiana Michigan Power
	Kentucky Power
	Public Service Oklahoma
	Southwestern Electric Power

Note: Multiple AEP Operating Companies allow the use of meter collar devices for backup power installations. Please refer to the appropriate Operating Company website for more information.

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 [Table 27](#) below to the latest tariffs in effect across the AEP system:

Table 27: 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



Operating Company	Link
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 28 below.

Table 28: Regional Tariff Links

Operating Company	RTO	Link
AEP Ohio	PJM	https://agreements.pjm.com/oatt/3897
AEP 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	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

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 Facilities 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.

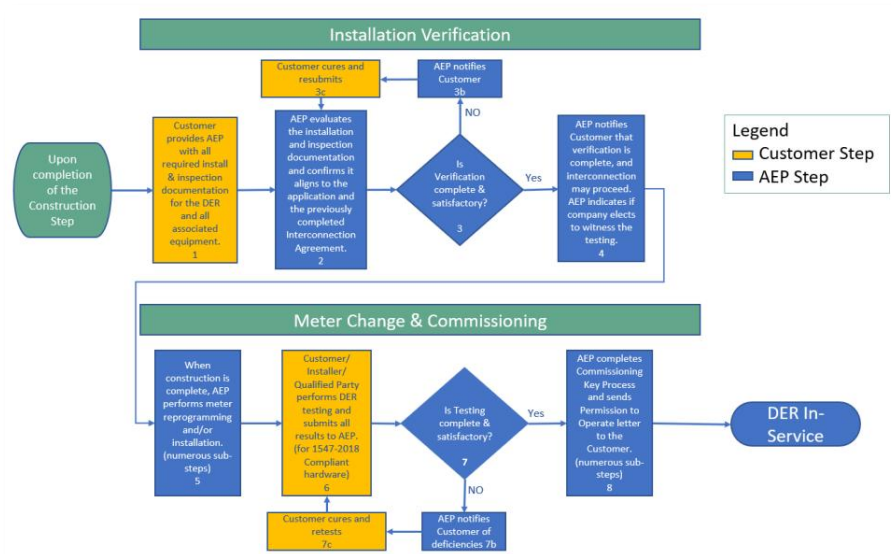
Specific commissioning and verification requirements for each project will be communicated during the interconnection process.

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 or the interconnection agreement between the DER Customer and AEP. 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 12 below illustrates AEP’s installation verification, meter change and commissioning process flow for interconnecting DER.

Figure 12: Process Flow for Commissioning-related steps of the DER Interconnection Process





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 DER 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 29](#) is provided to serve as guidance and may or may not be prescribed in the Customer's relay equipment inspection requirements.

Table 29: 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

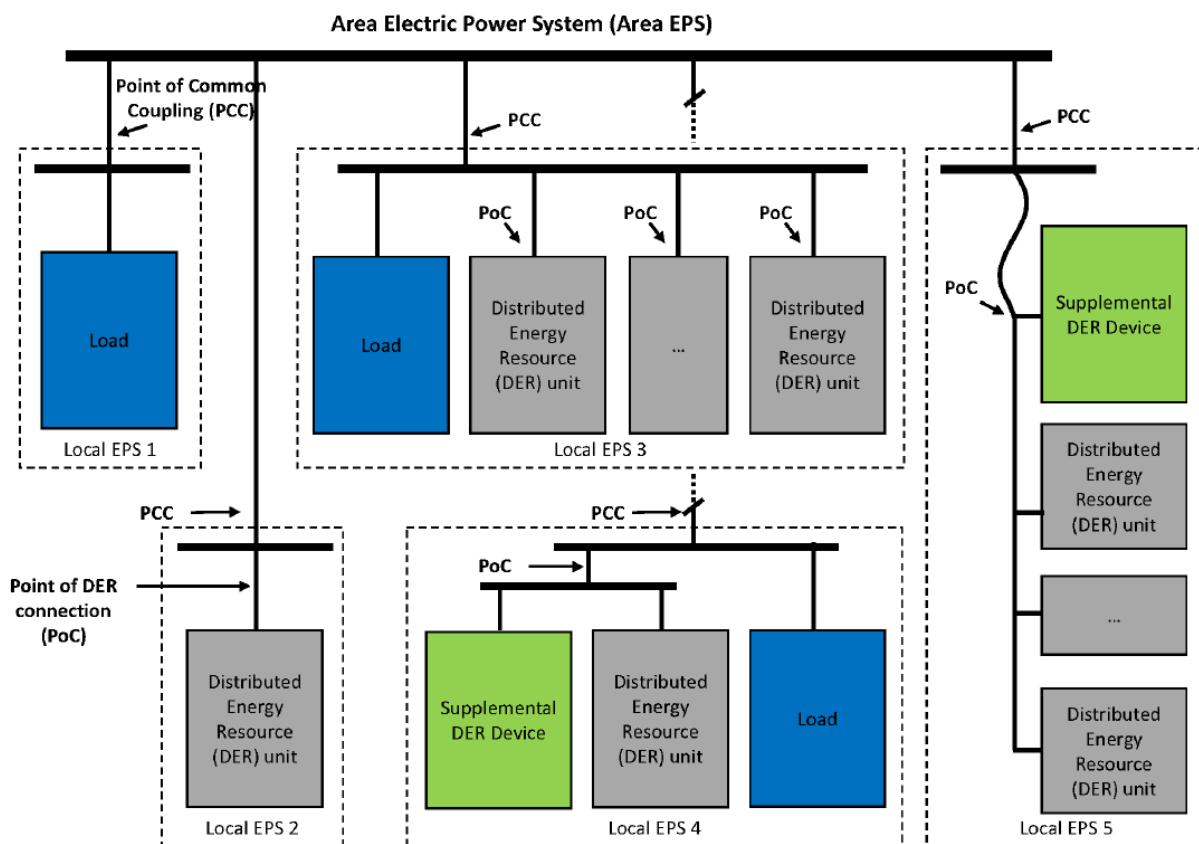
A.6 AEP Standards

- 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 13](#) below. For details related to these concepts, reference *IEEE Std 1547™-2018 Figure 2*.

Figure 13: Area EPS, Local EPS, PCC and PoC Exemplified





Appendix C: 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.
 - Where exceptions to the single isolation device standard are granted, each isolation device must be clearly labeled on the one-line diagram and at the physical installation as "Utility ACD x of y" where y is the total number of isolation devices.
- 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.
 - This includes any auxiliary load transformers for the DER Facility, as well as an estimate of the auxiliary load requirements during Summer and Winter periods.
- 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](#)

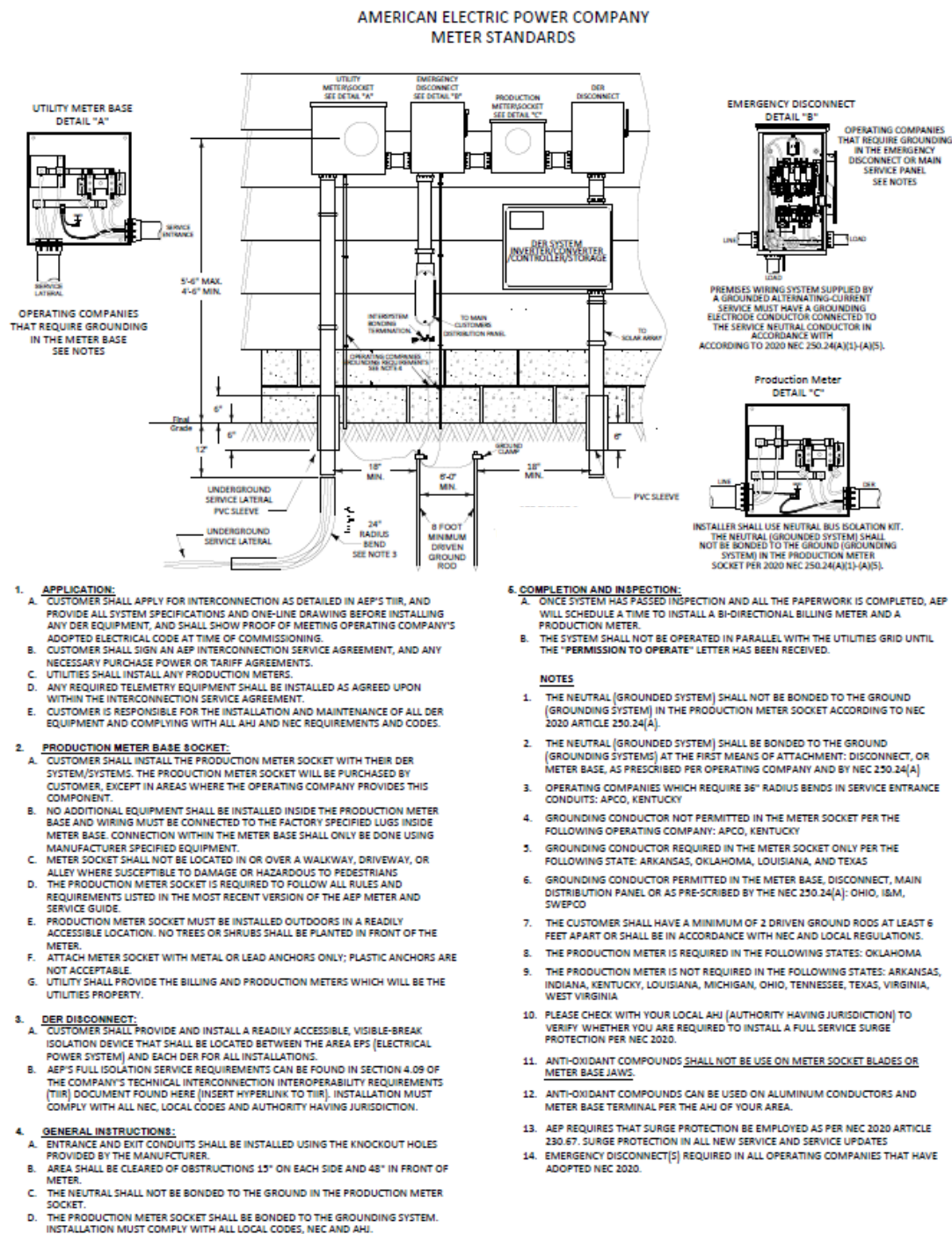
Applicants are responsible for ensuring that the submitted one-lines also adhere to requirements applicable by their state or local authorities.

The State of Michigan requires:

1. For interconnection applications with proposed DERs that fall into level 1, an applicant shall provide a 1-line diagram and a site diagram.
2. For interconnection applications with proposed DERs that fall into levels 2 and 3, an applicant shall provide a 1-line diagram that is either sealed by a professional engineer licensed in this state or signed by an electrical contractor who is licensed in this state with the electrical contractor's license number noted on the diagram. An applicant shall also provide a site diagram.
3. For interconnection applications with proposed DERs that fall into levels 4 and 5, an applicant shall provide a 1-line diagram that is sealed by a professional engineer who is licensed in this state. An applicant shall also provide a site diagram.

Appendix D: Residential DER system with Utility Billing Meter and Customer DER Production Meter

Figure 14: Residential DER system with Utility Billing Meter and the Customer DER Production Meter



Indiana Michigan (I&M) Power
Comments on Indiana Utility Regulatory Commission (IURC)
Rulemaking for FERC Order 2222

Indiana Michigan Power Company (“I&M” or “Company”) appreciates the opportunity to provide comments to the Indiana Utility Regulatory Commission (“IURC”) on Distributed Energy Resources and rulemaking for implementation of FERC Order 2222.

Distributed Energy Resource (DER) Aggregator – IURC Certification

1. The Commission should register all DER Aggregators to do business in Indiana. Registration should include:
 - a. Legal business name
 - b. Tax ID
 - c. Description of services provided to end use customers
 - d. Location (utility service territory) of services provided
 - e. Demonstration that all PJM/MISO DER Aggregation requirements have been met
 - f. Contact information for the DER aggregator for customers, Commission, utility inquiries
2. Commission should provide dispute resolution process for disagreements between DER Aggregators and their customers
3. Commission should explicitly give utilities the right to reject specific DER Facilities from being part of the DER Aggregation and state the reasoning which can include incomplete or conflicting information.
4. Rules should give the Commission authority to de-certify DER Aggregators that do not follow Commission rules, have unauthorized sales/aggregation practices, or have violated the PJM tariff.
5. Commission should consider whether DER Aggregators should be required to pay a registration/license fee to the Commission.
6. Does the Commission want to regulate the prices DERs are paid or whether or not the DER Aggregators have min contract terms or exit fees?

DER Aggregation Registration with the utility

- The Commission should establish rules that require utilities to (a) review each proposed DER Facility in the planned DER Aggregation to confirm that each generator or exporting storage resource is already properly approved and under an active Interconnection Agreement with the utility, (b) review/model proposed DER Aggregation from a distribution engineering perspective and (c) review DER Aggregation to ensure DER is not double

counted or already included in another DER Aggregation or retail tariff program before DER Aggregation is registered with PJM.

- Proposed DER Aggregation application to the utility should include the following:
 - a. Distribution utility for each component/DER in the aggregation
 - b. Account numbers for each component/customer (EDC Account Number retail premise, unique EDC reference number for point of interconnection), tariff code identifier
 - c. Description of the DER Facility intended to be part of the DER Aggregation
 - i. Address and/or utility meter number
 - ii. Resource type (PV, Stationary Battery, HVAC, Pool Pump, Electric Vehicle Charger, Synchronous generator, Parallel generator, Island generator, Water Heater, General Appliances, Other)
 - iii. Total capacity of DER resource
 - iv. Committed capacity (to the DER Aggregation)
 - d. Confirmation of injection capability at the Point of Common Coupling (PCC) and maximum injection capability at that point (utility meter)
 - e. Expected operating profile of the DER Aggregation and each member component
 - f. Indication that the Aggregator has verified the proper working condition of the asset and the existence of the Interconnection Agreement with the utility where appropriate (for example an Interconnection Agreement would not be required for a demand response program)
 - g. Which communication standards the devices are certified to meet, if any (examples include SunSpec ModBus, IEEE 1815 (DNP3) IEEE 2030.5 (SEP2), IEC 61850)
- Rules should allow the utility to charge the DER Aggregator for system studies, administrative fee for double counting analysis, and charges for IT programs/systems necessary to coordinate DER Aggregation.
- Rules should require that each DER Aggregation have a unique identifier with the Utility in order to simplify the dual enrollment/dual counting evaluations necessary.
- Limit on how frequently a component DER could change registration (e.g., cannot change aggregator within 1 year, changes to align with Delivery Year)
- Rules should allow utilities to report DER Aggregator violations to the Commission and for the Commission to take action to enforce the rules.
- Once the application is identified as complete by the utility, the utility should send notification (e.g., letter, email) about pending DER Aggregator registration that would change customer's current utility enrollments before the technical analysis begins. For example, this would allow a net metering customer to remove themselves from DER aggregation to prevent the DER from being counted as retail offset AND a DER resource in an Aggregation (preventing double counting).
- Rules should allow utilities to REMOVE customers from Aggregations by customer consent.
- Rules should allow utilities to respond to real-time operational conditions arising from the DER participating in the Aggregation. Such actions might include:
 - a. *requesting adjustments to inverter or control settings at the component DER level (i.e. change ramp rate, enable volt-watt function, etc.),*
 - b. *adjusting the participation capacity of component DER,*

- c. *requesting DER Aggregator to immediately stop participation with component DER or full Aggregation, or*
 - d. *the utility overriding the component DER by disconnecting the DER at the PCC, POI, or utility meter.*
- Rules should allow utility time to conduct a technical analysis before approving the DER Aggregation.
- If the DER Aggregation changes its operational profile after it is approved by the utility, the rules should allow for a utility to require a new technical analysis.
- Rules should establish minimum cyber security requirements for aggregators and aggregation software platforms that comply with industry standards (e.g., NIST, ISO/IEC 27001).
- The DER Aggregator would be required to sign a Distribution Interconnection Agreement for Wholesale Market access across the distribution system and identifying the delivery points impacted by the Aggregation.
- Rules should require DER Aggregators respond immediately to utility override orders for component DER or the entire aggregation in response to managing grid conditions.
- Rules should require the DER Aggregators make available to the utility the day ahead schedules for the DER Aggregation resources per the cleared bid.
- Rules should require the DER Aggregators submit to the utility any component DER planned outages.
- Rules should require the DER Aggregators establish data exchanges with the distribution utility to support real-time communication needs of the utility.
- Rules should require the Component DERs registering with an Aggregation meet the requirements of the latest utility interconnection requirements where necessary to support improved reliability of the distribution grid.

Utility DER database

1. Utilities will need to install back office systems to keep track of DERs and DER Aggregations that coordinate with their billing system.
2. Utility DER database will ensure customer/DER personal identifiable information (PII) is protected just as it does with customer PII.
3. Some/most of the cost of the database should be borne by DER Aggregators and/or DERs.
4. Timing of when Indiana utilities need to have systems in place to accommodate DER Aggregations.

Utility DER Aggregation Tariff

1. Existing DR Aggregation tariffs should be maintained as they provide benefits to all customers as it contributes to I&M's capacity plan without markups by third parties.
2. I&M believes a DER Aggregation tariff might be necessary, but it is premature to know what types of provisions and obligations should be included in the tariff given the market has not

been fully developed. In order to develop appropriate tariffs, the following aspects need to be better understood:

- a. How will DERs be paid by DER aggregators? Utility bill credit – if so how does utility get reimbursed? Who pays for the bill programming? Monthly checks?
 - b. What are the penalties the DER aggregator will incur if they do not operate in compliance with distribution grid protocols?
 - c. Impacts on utility's capacity needs? If the DERs are no longer offsetting utility capacity needs how does that change the utilities capacity plans (FRR)? Should DER Aggregation be limited to a specific delivery year like other PJM DR products?
 - d. Is there a cap on DER Aggregation participation in Indiana until financial and operational impacts are known?
3. Existing Demand Response, Net Metering, and Excess Distributed Generation riders need to be updated to state that the customer cannot also be enrolled in PJM DER Aggregation to avoid double counting.