Marshall County REMC

Distributed Generation Technical Requirements

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Description:	DER Technical Requirements for Interconnection to the Marshall County REMC Distribution System

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SECTION 1: SCOPE & APPLICABILITY

1.1 SCOPE AND APPLICABILITY

1.1.1 SCOPE AND APPLICABILITY

This Distributed Energy Resource (DER) Technical Requirements document specifies the technical requirements for the interconnection of DERs to the Cooperative's Electrical Power System (EPS). In some cases, Transmission and Power Purchase Agreements (PPA) requirements may apply in addition to the requirements specified in this document. All applicable requirements will be reviewed with interconnecting customers during the interconnection process.

Backup power systems that are designed and tested to verify that they only operate when the premise is not connected to the Cooperative EPS are not required to complete the DER Interconnection Service Request process or have an interconnection service agreement with the Cooperative. A generator using a make-before-break transfer scheme where the generator is paralleled less than 100 milliseconds with the EPS does not fall under the interconnection rules for Distributed Resources in most jurisdictions. However, proposed make-before-break transfer scheme generator equipment packages must be reviewed and approved by the Cooperative. The package must meet the requirements of Underwriters Laboratories Standard 1008 and be listed by a nationally recognized testing laboratory.

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

Requirements included in this document shall apply to all DER interconnection requests received on or after January 1, 2024. Any DER installations in operation before January 1, 2024 shall be deemed to be "grandfathered" in by the Cooperative and may continue to meet the interconnection requirements in effect at the time of application. Should "grandfathered" DER interconnections be materially modified, they shall be required to meet the current requirements of this document.

The Cooperative reserves the right to modify or update DER requirements on a case-by-case basis at its sole discretion.

1.1.2 IEEE STD 1547-2018

The most recent version of *IEEE 1547-2018, IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces*, and its subparts shall apply to these Technical Requirements. These requirements are referred to as IEEE 1547 for the remainder of this document.

The Reference Point of Applicability (RPA) is defined as the Point of Common Coupling (PCC) as defined in IEEE 1547.

1.1.3 RESPONSIBILITIES

The Customer is responsible for designing, installing, operating, and maintaining its own equipment in accordance with interconnection agreements and applicable standards, including IEEE 1547. 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

This document does not remove the Customer's responsibility for reading, understanding, and complying with all content of IEEE 1547 and all applicable local codes, standards, statutes, and commission orders.

Coordination between the Cooperative and the Customer is necessary, as the EPS is constantly changing. At times, changes in the Cooperative's system may necessitate updates to protection and control, or other parameters at a DER facility. The Cooperative 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. The Cooperative requires the Customer to take responsibility for implementing changes in accordance with the Interconnection Agreement.

SECTION 2: TECHNICAL REQUIREMENTS

2.1 GENERAL TECHNICAL REQUIREMENTS

2.1.1 REFERENCE POINT OF APPLICABILITY (RPA)

Reference Point of Applicability (RPA) defines the physical location the requirements of this standard must be met for testing, evaluation, and commissioning. The RPA location is the Point of Common Coupling (PCC) as defined by IEEE-1547 for Level 2 and Level 3 DER sources. However, the RPA may be the Point of DER Connection (PoC) for Level 1 sources, upon agreement by the Cooperative.

2.1.2 EFFECTIVE GROUNDING AND TRANSFORMER REQUIREMENTS

The Cooperative maintains a four-wire, grounded-wye EPS. The DER is required to do the following as it relates to effective grounding and DER transformers:

- Maintain DER system ground integrity
- Minimize abnormal transient overvoltage amplitude during system or DER events
- Ensure distribution primary ground source configuration cannot be separated from the DER while the DER is providing capacity to the distribution system primary equipment facilities.
- Ensure single-phase transformer windings grounded on the secondary (LV) bushings to the DER (preferred).
- Ensure single-phase transformer windings ungrounded on the transformer secondary only when the customer side is grounded in accordance with NEC 2023 rule 250.4(B)(4) and that this is demonstrated in the provided electrical one-line diagram.
- Ensure transformer winding connected to the distribution system primary shall match the grounding configuration of the distribution system primary
- DER may not be interconnected to the distribution system primary utilizing an autotransformer as the interconnection transformer. An autotransformer is a transformer that uses a common winding for both the primary and secondary windings.
- DER are not permitted to connect to an open-delta service transformer configuration, regardless of the DER being a single-phase or multi-phase system
- Three-phase DERs may only be connected to three-phase feeders
- Ensure DER grounding scheme shall be coordinated with the ground fault protection of the Area EPS.

2.1.3 ACCEPTABLE TRANSFORMER CONFIGURATIONS

Following three-phase and single-phase transformer connections may be acceptable for connecting the DER to the Cooperative’s 4-wire, grounded-wye EPS, subject to completing a DER screening or impact study, as well as applicable site inspection(s).

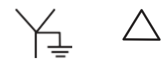
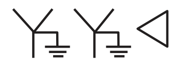
Winding Configuration	Transformation Primary (Pri.) Secondary (Sec.)
Grounded Wye/Delta	
Grounded Wye/ Grounded Wye with a Delta Tertiary	

Table 1 – 3 Phase Transformer Connections Regardless of DER Configuration

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

Table 2 – 3 Phase Transformer Connections only for Grounded-Wye DER Configuration

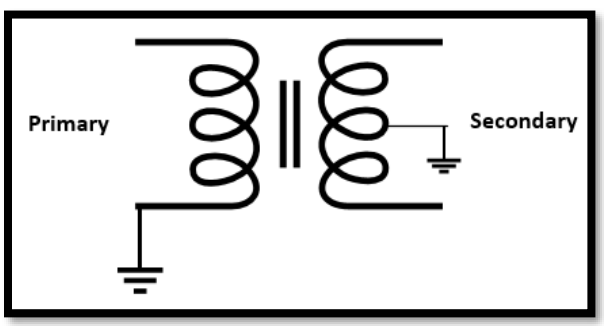


Figure 1 – Preferred Single Phase Transformer Connections

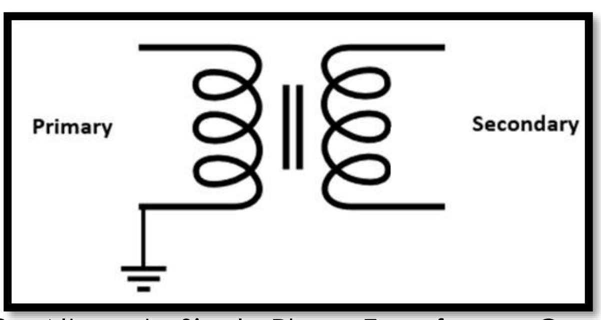


Figure 2 – Alternate Single Phase Transformer Connection
Customer Grounding per NEC 2023 rule 250.4(B)(4)

2.1.4 OPEN-PHASE DETECTION

The DER shall detect, cease to energize, and trip all phases of the DER for any open-phase condition at the RPA. The DER shall cease to energize and trip within 2.0 seconds of the open-phase condition.

2.1.5 CEASE TO ENERGIZE

During cease to energize events, the DER may separate from the Cooperative EPS but continue to deliver power to the portion of the customer EPS that is disconnected from the Cooperative's area EPS.

2.1.6 REMOTE CONTROL CAPABILITY REQUIREMENTS

Level 2 and Level 3 DER sources shall be capable of accepting external commands, including cease to energize, modify power delivery and update mode or parameter changes. The Cooperative may curtail DER production based on system conditions or operating requirements.

2.1.7 PRIORITIZATION OF DER RESPONSE

The DER shall respond as stated in IEEE 1547-2018 Clause 4.7.

2.1.8 MANUAL ISOLATION DEVICE

A readily accessible, lockable, visible-break isolation device shall be located between the Cooperative's EPS and the DER. Only a single isolation device shall be permitted between the Cooperative's EPS and the DER. The single isolation device shall allow the separation of the DER with a single operation.

The isolation device shall be located withing 6 feet of the Cooperative's electric meter and between 4 and 6 feet above grade. The isolation device shall be clearly marked with "DER Disconnect Switch". Should the isolation device be unable to be located as required, a permanent sign shall be installed next to the electrical meter noting the location of the DER isolation switch.

The isolation device shall be properly maintained and in good working order.

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.

For Level 2 and Level 3 DER sources, the Cooperative reserves the right to install a Cooperative-owned and controlled disconnecting device on the Cooperative side of the Point of Common Coupling (PCC).

2.1.9 MANUAL ISOLATION DEVICE

The Cooperative requires that any DER facility with a total nameplate capacity of 500 kW or larger that is not collocated with site load (i.e., a residential, a commercial or industrial customer), shall include an Cooperative-owned and controlled disconnect switch, furnished and installed by the Cooperative, and to be located on the Cooperative side of the Point of Common Coupling (PCC) or a location approved by the Cooperative.

Where the DER facility interconnects to a circuit that is part of a local Distribution Automation (DA) scheme, the Cooperative-owned and controlled disconnect switch may be integrated into the DA scheme. The DER may be required to disconnect under alternate grid configurations.

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

2.1.10 INADVERTENT ENERGIZATION OF AREA EPS

The DER shall not energize the Cooperative's EPS when the area EPS is de-energized. Exceptions may be given for intentional area EPS at the discretion of the Cooperative. Only DER facilities owned or operated by the Cooperative may serve facilities in the area EPS during an intentional island.

2.1.11 ENTER SERVICE CRITERIA

The DER shall meet the default Enter Service settings for all categories of DER as stated in IEEE 1547-2018 Clauses 4.10.2 and 4.10.3.

2.1.12 SYNCHRONIZATION

The DER shall meet the default Synchronization settings for all categories of DER as stated in IEEE 1547-2018 Clause 4.10.4.

2.1.13 ELECTROMAGNETIC INTERFERENCE (EMI)

The DER shall meet the default Electromagnetic Interference (EMI) protection requirements for all categories of DER as stated in IEEE 1547-2018 Clause 4.11.1. The Cooperative reserves the right to request and review or approve documentation demonstrating the DER's EMI withstand capabilities.

2.2 DER GRID SUPPORT

2.2.1 REACTIVE POWER CAPABILITIES

The DER shall meet the Reactive Power Capabilities as stated in IEEE 1547-2018 Clauses 5.1 and 5.2. The Cooperative has defined performance capabilities for all DER as shown in Table 3 below. The Cooperative reserves the right to modify or update DER performance capabilities on a case-by-case basis at its sole discretion.

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

Table 3 – Reactive Power Capability Performance Category by Energy Source

Operation at any active power output above 20% of rated active power shall not constrain the delivery of reactive power injection or absorption, up to the capability specified in Table 4 (IEEE 1547-2018 Table 7), as required by the active control function at the time, as defined in Section 2.2.2. Curtailment of active power to meet apparent power constraints is permissible. These reactive power requirements are illustrated in Figures 3 and 4 (IEEE 1547-2018 Figure H.3).

Category	Injection capability as % of nameplate apparent power (kVA) rating	Absorption capability as % of nameplate apparent power (kVa) rating
A (At DER Rated Voltage)	44	25
B (Over ANSI C84.1 Full Range A)	44	44

Table 4 – Minimum Reactive Power Injection and Absorption Capabilities

The DER is required to meet these criteria at the Reference Point of Applicability (RPA). For DER with multiple inverters, typically a site controller will be required to control the combined DER inverter output.

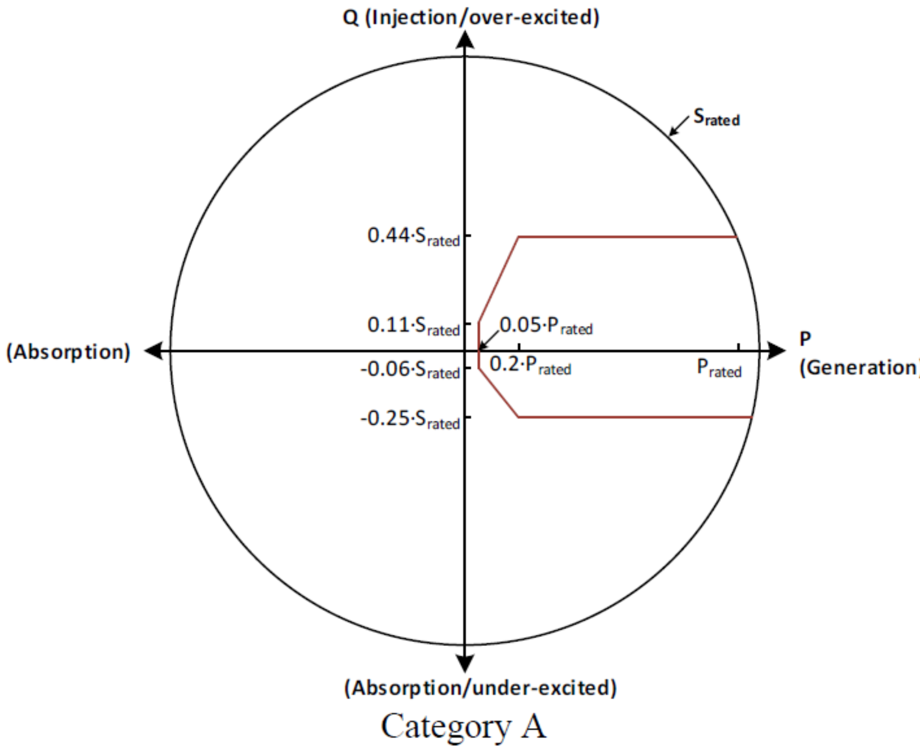


Figure 3 – Category A DER Minimum Reactive Power Capabilities

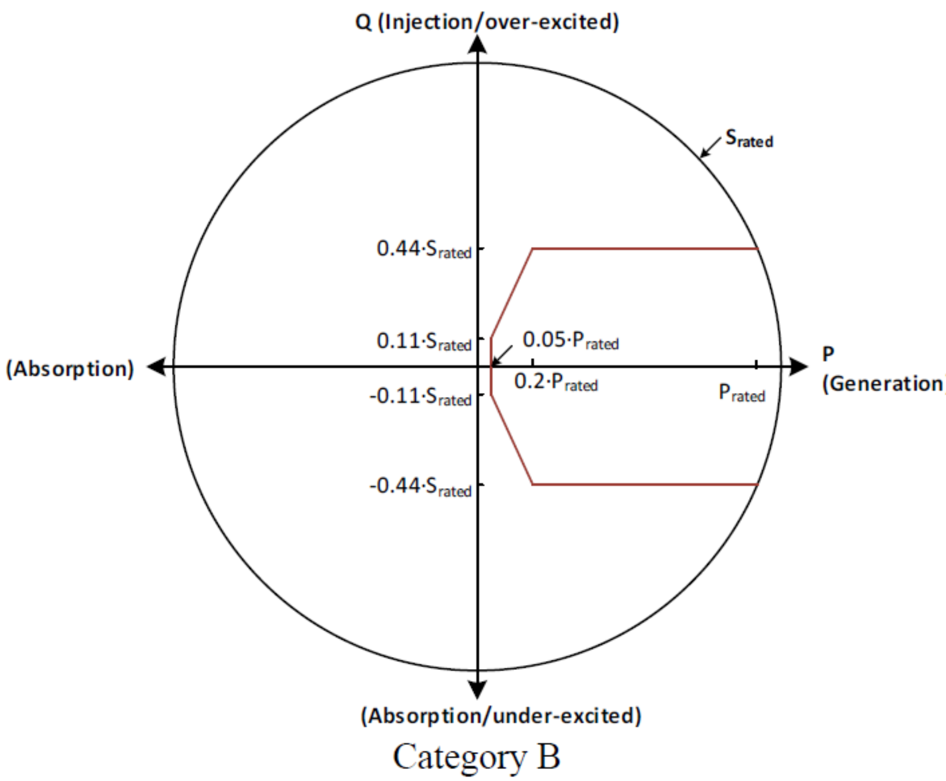


Figure 4 – Category B DER Minimum Reactive Power Capabilities

2.2.2 REACTIVE POWER CONTROL

The Cooperative requires Volt-Var settings shown below in Figure 5 for connected DER. Modifications to these settings shall only be made at the Cooperative's request. The Cooperative reserves the right to modify DER reactive power control mode and settings at its sole discretion.

Constant Power Factor, Active Power, and Constant Reactive Power operating modes shall all be disabled by default.

The DER is required to meet these criteria at the Reference Point of Applicability (RPA). For DER with multiple inverters, typically a site controller will be required to control the combined DER inverter output.

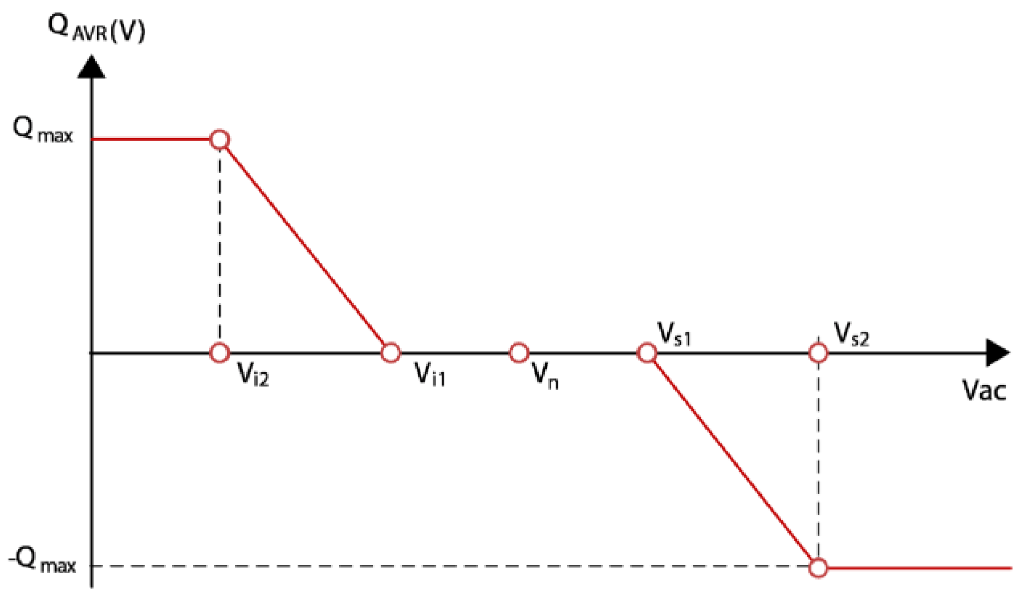


Figure 5 – Volt-Reactive Power (Volt-Var) Operating Power Control Settings

Volt-Reactive Power (Volt-Var Mode)	Value	Description
V_n	1.0 pu	Reference Voltage
V_{s1}	1.02 pu	Reactive Power Absorption Setpoint
V_{s2}	1.08 pu	Upper Limit for DER Continuous Operation
V_{i1}	0.98 pu	Reactive Power Injection Setpoint
V_{i2}	0.92 pu	Lower Limit for DER Continuous Operation

Table 5 – Volt-Reactive Power (Volt-Var) Operating Power Control Settings

2.3 DER RESPONSE TO ABNORMAL CONDITIONS

2.3.1 DER RESPONSE TO ABNORMAL CONDITIONS PERFORMANCE CATEGORIES

The Cooperative-required DER Response Categories by energy source are specified in Table 6 below. The Cooperative reserves the right to modify DER Response Categories at its sole discretion.

Power Source	Prime Mover/Energy Source	Response Category
Inverter	Solar PV, Battery Energy Storage	Category III[1] (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

Table 6 – DER Response Categories by DER Source

2.3.2 COOPERATIVE EPS FAULTS

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

2.3.3 OPEN PHASE CONDITIONS

In accordance with IEEE 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.

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

2.3.4 COOPERATIVE EPS RECLOSING COORDINATION

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

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

2.3.5 VOLTAGE RIDE-THROUGH CAPABILITY REQUIREMENTS AND TRIP SETTINGS

In accordance with IEEE 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 Cooperative's EPS and trip within the respective clearing time as indicated.

The Cooperative requires the default settings shown in Table 7 through Table 9 below be applied to connected DER for the different response categories. Site-specific modifications to these settings shall only be made at the Cooperative's request. The Cooperative reserves the right to modify these settings at its sole discretion.

Shall Trip to Abnormal Voltages - Category I DER					
Shall Trip Function		**Cooperative-Required Setting**		**Ranges of Allowable Settings**	
		Voltage (p.u. of Nominal Voltage[2])	**Clearing Time (s)**	**Voltage (p.u. of Nominal Voltage[2])**	**Clearing Time (s)**
OV2	Over Voltage Level 2	1.20	0.16	Fixed at 1.20	Fixed at 0.16
OV1	Over Voltage Level 1	1.10	2.0	1.10 – 1.20	1.0–13.0
UV1	Under Voltage Level 1	0.70	2.0	0.0 – 0.88	2.0–21.0
UV2	Under Voltage Level 2	0.45	0.16	0.0 – 0.50	0.16–2.0

Table 7 – Voltage Trip Settings for Category I DERs

Shall Trip to Abnormal Voltages - Category II DER					
Shall Trip Function		**Cooperative-Required Setting**		**Ranges of Allowable Settings**	
		Voltage (p.u. of Nominal Voltage[2])	**Clearing Time (s)**	**Voltage (p.u. of Nominal Voltage[2])**	**Clearing Time (s)**
OV2	Over Voltage Level 2	1.20	0.16	Fixed at 1.20	Fixed at 0.16
OV1	Over Voltage Level 1	1.10	2.0	1.10 – 1.20	1.0–13.0
UV1	Under Voltage Level 1	0.70	10.0	0.0 – 0.88	2.0–21.0
UV2	Under Voltage Level 2	0.45	0.16	0.0 – 0.50	0.16–2.0

Table 8 – Voltage Trip Settings for Category II DERs

[2] Nominal system voltages stated in ANSI C84.1, Table 1 or as otherwise defined by the Cooperative.

Shall Trip to Abnormal Voltages - Category III DER					
Shall Trip Function		Cooperative-Required Setting		Ranges of Allowable Settings	
		Voltage (p.u. of Nominal Voltage[3])	Clearing Time (s)	Voltage (p.u. of Nominal Voltage[3])	Clearing Time (s)
OV2	Over Voltage Level 2	1.20	0.16	Fixed at 1.20	Fixed at 0.16
OV1	Over Voltage Level 1	1.10	13.0	1.10 – 1.20	1.0–13.0
UV1	Under Voltage Level 1	0.88	21.0	0.0 – 0.88	2.0–21.0
UV2	Under Voltage Level 2	0.50	2.0	0.0 – 0.50	0.16–2.0

Table 9 – Voltage Trip Settings for Category III DERs

2.3.6 FREQUENCY RIDE-THROUGH CAPABILITY REQUIREMENTS AND TRIP SETTINGS

All connected DER shall perform in accordance with the frequency performance requirements as specified in IEEE 1547-2018 Clause 6.5. In accordance with IEEE 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.

The Cooperative requires the abnormal frequency trip settings shown in Table 10 below be applied to connected DER for the different response categories. Site-specific modifications to these settings shall only be made at the Cooperative's request. The Cooperative reserves the right to modify these settings at its sole discretion.

Shall Trip to Abnormal Frequencies —Category I, Category II, Category III DER					
Shall Trip Function		Cooperative-Required Setting		Ranges of Allowable Settings	
		Frequency	Clearing Time (s)	Frequency	Clearing Time (s)
OF2	Over Frequency Level 2	62.0	0.16	61.8 – 66.0	0.16 – 1000.0
OF1	Over Frequency Level 1	61.2	300.0	61.0 – 66.0	180.0 – 1000.0
UF1	Under Frequency Level 1	58.5	300.0[4]	50.0 – 59.0	180.0 – 1000.0
UF2	Under Frequency Level 2	56.5	0.16	50.0 – 57.0	0.16 – 1000.0

Table 10 – Voltage Trip Settings for Category III DERs

[3] Nominal system voltages stated in ANSI C84.1, Table 1 or as otherwise defined by the Cooperative.

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

2.4 POWER QUALITY

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

The Cooperative reserves the right to request that the Customer provide evidence confirming the conformance of installed DER equipment to the power quality requirements presented in this section.

The Cooperative 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.

2.4.1 LIMITS 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.

2.4.2 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).

2.4.3 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.

2.4.4 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 11 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 as defined in IEEE Std 1453 and IEC/TR 61000-3-7.

E_{Pst}	E_{Plt}
0.35	0.25

Table 11 – Minimum individual DER flicker emission limits[5]

2.4.5 CURRENT DISTORTION LIMITATIONS

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 12 and Table 13 below).

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

Table 12 – Maximum Odd Harmonic Current Distortion in Percent of Rated Current (I_{rated})[6]

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

Table 13 – Maximum Even Harmonic Current Distortion in Percent of Rated Current (I_{rated})[6]

[5] 95% probability value should not exceed the emission limit based on a one week measurement period.
[6] I_{rated} = the DER unit rated current capacity (transformed to the RPA when a transformer exists between the DER unit and the RPA).

2.4.6 COMPATIBILITY WITH VOLTAGE REGULATION EQUIPMENT

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

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

- **Voltage Regulators:** Voltage changes are limited to ½ the bandwidth of any voltage regulator (line or substation) measured at the regulating device.

- **Capacitors:** Voltage changes are limited to ½ the net dead bandwidth of any switched capacitor bank measured at the device.

- **VAR Switched Capacitors:** Reactive power changes are not to exceed ½ the bandwidth of any VAR switched capacitor bank measured at the device.

2.5 PROTECTION INTEGRATION REQUIREMENTS

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 Cooperative EPS.

2.5.1 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.

The Cooperative requires that the DER identify and disclose the method of unintentional islanding detection for DER installations with a total aggregate capacity of 200 kW or greater.

2.5.2 INTENTIONAL ISLANDING

The Cooperative 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 the Cooperative to provide islanding service (including customer owned DER assets) may serve facilities in the Cooperative Area EPS in an intentional island.

2.5.3 DIRECT TRANSFER TRIP PROTECTION

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

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

2.5.4 DER SYSTEM PROTECTION REQUIREMENTS

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

DER protection systems shall include, but not be limited to, phase and ground fault overcurrent protection and shall be subject to Cooperative review. This protection is required to be coordinated with Cooperative 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 the Cooperative's request, including any revised final drawings.

The Customer shall make changes that Cooperative requires prior to parallel operation.

2.5.5 DER PROTECTION SETTINGS REVIEW AND RETENTION REQUIREMENTS

Protection and automation device settings are required to be coordinated, reviewed, and documented between the Cooperative and DER owner. Setting changes to protection and automation equipment that affects the operation of Area EPS-connected DER shall be reviewed by the Cooperative 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 Cooperative for review.

Any protective relay, control device, inverter controller, etc. that is affected by a material modification shall trigger a review of any affected or adjacent device settings by the Cooperative 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 the Cooperative 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 DER 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.

SECTION 3: GRID REQUIREMENTS FOR RADIAL-CONNECTED DER

3.1 RADIAL-CONNECTED DER REQUIREMENTS

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

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

3.1.1 REVIEWED IMPACTS

The Cooperative 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.

If a DER is determined to reach or exceed any of the limits captured in Sections 3.1.2 through 3.1.6, mitigation shall be required. It will be developed through the interconnection process and implemented prior to DER operation. The proposed mitigation may include site-specific customized DER control and response settings.

3.1.2 STEADY STATE VOLTAGE LIMITS

Cooperative steady state voltage limits are based on the ANSI C84.1 Range A limits for primary and secondary distribution systems. Table 14 below documents the operating limits established by the Cooperative for steady state voltage during normal or contingency conditions.

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

Table 14 – Steady State Voltage Limits

3.1.3 THERMAL IMPACT LIMITS

All thermal impact limits specified in Section 3.1.3 shall be assessed considering the lesser of the total nameplate capacity or the total self-limited output capacity of connected DER.

All thermal ratings considered shall be based on unbalanced load conditions and that the thermal limit of all protective devices (e.g., breakers, reclosers, and fuses) across the Cooperative distribution system will be evaluated at 85% of their continuous rating.

- **Distribution Station Power Transformer**: Distribution station transformer loading shall be limited to no greater than the seasonal (summer and winter) normal capability ratings when operating in a reverse power flow direction.
- **Distribution Service Transformer**: Distribution service transformer loading shall be limited to no greater than the nameplate kVA rating when operating in a reverse power flow direction.
- **Distribution Feeder Limits**: Distribution feeder limits are shown below in Table 15.

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

Table 15 – Distribution Feeder Limits

- **Distribution Voltage Regulator Limits**: Distribution voltage regulator limits are shown below in Table 16.

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

Table 16 – Distribution Feeder Limits

3.1.4 SHORT CIRCUIT LIMITS

The short circuit limit of all protective devices (e.g., breakers, reclosers, and fuses) across the Cooperative distribution system will be evaluated at 85% of their interrupting rating.

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

3.1.5 REVERSE FLOW LIMITS

A DER connected to the Cooperative 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 coordinated with the Cooperative's transmission provider, Wabash Valley Power Alliance (WVPA).

3.1.6 MULTIPLE RADIAL SERVICE LIMITS

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 Cooperative-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.

3.1.7 DER OPERATION DURING ABNORMAL CONDITIONS

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

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

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

3.1.8 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, P_{rated} (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 1 of this document:

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

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

SECTION 4: DER INTEROPERABILITY, TELEMETRY, AND CYBER SECURITY

4.1 GENERAL REQUIREMENTS

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

This section defines additional Cooperative 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.

4.1.1 DER REQUIREMENTS AT OR ABOVE 500 KW

The Cooperative requires that SCADA telemetry be implemented at both the Site Controller and the SCADA controlled disconnect switch (where applicable per Section 2.1.8 of this document) for any DER 500 kW or larger for monitoring and control purposes.

4.1.2 DER REQUIREMENTS AT OR ABOVE 200 KW AND LESS THAN 500 KW

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

4.1.3 DER ADDITIONAL REQUIREMENTS

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

For DER installations that use a Site Controller to manage multiple inverters, the Site 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 the Cooperative from the DER is good (98% and above availability) and accurate. The Cooperative reserves the right to request additional testing to confirm the accuracy of measurements and to have the Customer remediate measurement issues.

4.2 INTEROPERABILITY REQUIREMENTS

The telemetry interface(s) through an RTU that the Cooperative 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.

4.2.1 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 17 below).

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

Table 17 – Distribution Feeder Limits

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

Table 17 – Distribution Feeder Limits Continued

4.2.2 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 the Cooperative. Configuration settings may be used by the Cooperative to deviate from nameplate values. Configuration settings are not intended for continuous dynamic adjustment.

4.2.3 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 18 below). The information shall be the latest value that has been measured within the required response time.

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

Table 18 – DER Monitoring Information

Parameter	Description
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

Table 18 – DER Monitoring Information Continued

4.2.4 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.

The Cooperative 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 the Cooperative.

4.3 DER COMMUNICATION INTERFACE 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 Cooperative - approved communication means to provide all telemetry and control that is required to meet the telemetry requirements identified throughout this document. The Cooperative will specify all necessary communication information sharing requirements for DER interconnection. Specific details of telemetry requirements will be provided during the interconnection process.

4.3.1 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, The Cooperative supports serial IEEE Std 1815 (DNP3) and serial Modbus protocols for use as communication interfaces.

4.3.2 DER UNLOCK MECHANISM REQUIREMENTS

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

4.3.3 DER NETWORK ADAPTERS

As required, the Cooperative will provide and install the telemetry and network adapters required for interoperability of the DER Facility with the Cooperative'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.

4.3.4 DER 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. The Cooperative reserves the right to disconnect DER from the Area EPS for any cyber related concern until the concern is remediated. Ultimately, the DER facility owner is responsible for the Cyber Security of the DER facility.

Further, the DER facility owner should consider and implement, 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

SECTION 5: IMPACT STUDY

5.1 IMPACT STUDY

5.1.1 IEEE 1547.7 SYSTEM IMPACT STUDY

The following items are required to be developed and submitted by the Producer to the Cooperative for review. The development and associated cost are the responsibility of the Producer. It is anticipated the Producer will develop the project to a conceptual level of detail to make the utility review possible, typically a 20-30% design. The purpose of the conceptual review is to allow the Producer to identify any utility-required projects. The outcome of the System Impact Study is to allow the Producer to determine project viability inclusive of utility requirements.

The Producer should allow 1-2 months to complete the System Impact Study once the Cooperative is in receipt of the required submittals below.

5.1.2 CONCEPTUAL DESIGN SUBMITTALS

The following items are required to be developed and submitted by the Producer to the Cooperative for review. The development and associated cost are the responsibility of the Producer. It is anticipated the Producer will develop the project to a conceptual level of detail to make the utility review possible, typically a 20-30% design. The purpose of the conceptual review is to allow the Producer to identify any utility-required projects. The outcome of the System Impact Study is to allow the Producer to determine project viability inclusive of utility requirements.

The Producer should allow 1-2 months to complete the System Impact Study once the Cooperative is in receipt of the required submittals below.

<u>Conceptual Design Required Items</u>

1. Utility application and listed supporting documentation
2. Project Narrative describing the following:
    a. Project introduction, description and goals
    b. All operating modes (normal and abnormal conditions)
    c. Maximum MW/MVAR output
    d. Description of how the project will meet IEEE-1547 and MISO requirements
3. Single-line diagram of the system showing all major electrical equipment from the generator to the point of interconnection with the utility system, including generators, transformers, switchgear, switches, breakers, fuses, protection components (CT/PT's), instrument transformers, auxiliary equipment, switching requirements, etc.
4. Three-line diagram of generator and auxiliary system package
5. Control drawings for relays and breakers.
6. Site Plans showing the physical location of major equipment.
7. Relevant ratings of equipment. Transformer information should include capacity ratings, voltage ratings, winding arrangements, and impedance.

8. Protection system description including protection package, disconnecting means, synchronizing capabilities, etc.
    a. Planned settings functions applicable to the interconnection protection and a description of how the relay is programmed to operate as applicable to interconnection protection.
9. Generator models and parameters for use in power flow and other simulation programs
    a. For Synchronous Generators, manufacturer and model number and all other Nameplate ratings and impedance data.
    b. Machine Data (per unit)
    c. Synchronous Reactance Xd
    d. Transient Reactance X'd
    e. Subtransient Reactance X"d
    f. Negative Sequence X2
    g. Zero Sequence X0
    h. Armature Winding Resistance R1, R2 and R0
    i. Machine Capability Curves
10. Inverter-Based Generation, include the following:
    a. Inverter/Solar Panel Manufacturer
    b. Model(s)
    c. Data Sheets/Instruction Manuals/Applicable Supporting Documentation
    d. UL1741 (and other Applicable Industry) Ratings and Certifications
11. Interconnection Transformer
    a. Nameplate Ratings / Data
    b. Capacity Self-Cooled/Maximum Nameplate KVA Winding
    c. Voltage (Low V/High V/Tertiary V) Winging Phase
    d. Relationship (Delta or Wye)
    e. Fixed Taps available/Present Tap Setting
    f. Automatic Tap Changer available Taps/Present Setting
    g. Impedance
    h. Positive Z1 (% on self-cooled kVA rating) and X/R Zero Z0 (% on self-cooled kVA rating) and X/R
12. Proof of Site Control
    a. Proof of site control consists of documentation demonstrating ownership, leasehold interest in, or right to develop a site for the purpose of constructing a generating facility.
13. Local Operations & Maintenance Points of Contact
14. Proof of Insurance
15. Requested Testing and Commissioning Dates
16. Requested In-Service Dates

5.1.3 IEEE 1547.7 SYSTEM IMPACT STUDY

Alpha Engineering and the Cooperative will use the conceptual information provided above to perform a System Impact Study as required by IEEE 1547.7. The purpose of the study is to ensure the Distribution System integrity and the safety of operations personnel and the public are maintained.

The Producer should be aware that corrective actions identified during the System Impact Study shall be met at the Producer's expense before the project can become operational. Should corrective actions be required, it could add costs and time to the project. It is not uncommon for significant utility projects to require 12-24 months for design, procurement, and construction.

SECTION 7: METERING REQUIREMENTS

6.1 METERING REQUIREMENTS

6.1.1 REVENUE-GRADE METERING

DER facility revenue metering is required by the Cooperative for all Customers. DER that elect to interconnect to Cooperative Facilities carry the same requirements. To achieve this requirement, the Cooperative will provide and deploy appropriate facility revenue metering for each DER installation. The Cooperative strives to directly measure and capture the energy produced and consumed by connected DER through standardized metering equipment.

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

6.1.2 SINGLE-METERED DER

Single-Metered DER will use a bidirectional Service 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 Cooperative's EPS. These values will be recorded in separate registers of the meter.

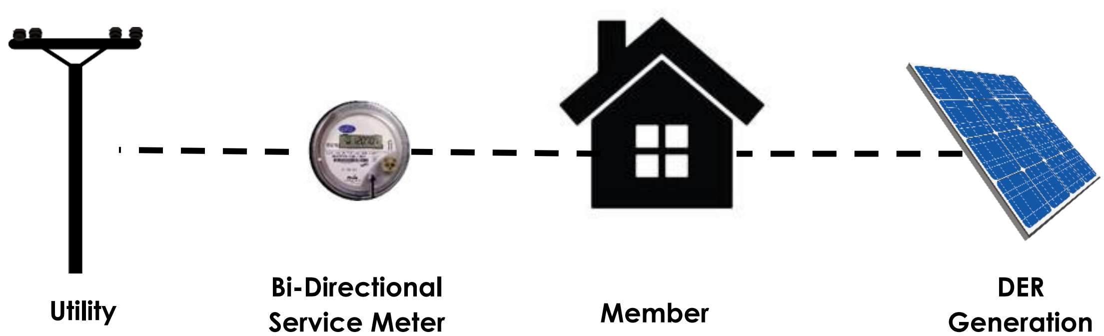


Figure XX – Single-Metered DER Illustration

6.1.3 MULTI-METERED DER (POWER PRODUCTION METER)

Multi-Metered DER installations will use a bidirectional Service Meter that measures energy delivered to the Customer as well as any excess generation the Customer puts back onto the Cooperative's EPS. These installations will also use one or more bidirectional Power Production Meters that measure the output of the Customer's DER units. The Power Production Meter will also be programmed to register and record usage in each direction.

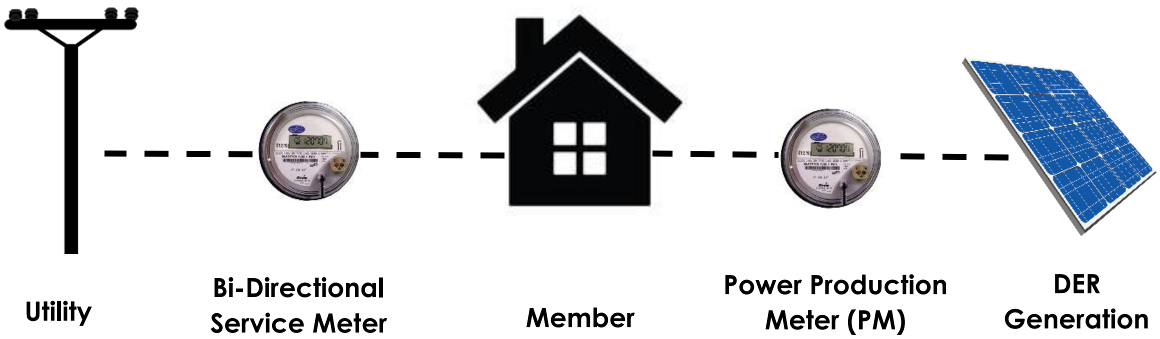


Figure XX – Multi-Metered DER Illustration

6.1.4 METERING INSTRUMENTATION

Some commercial and industrial services require the use of current transformers (CT) and/or potential transformers (PT). In these cases, the PoC meter will require the use of high accuracy current transformers and potential transformers.

Metering CTs shall have a high accuracy, extended range, 0.15% accuracy class or better.

Metering PTs shall have a high accuracy, 0.15% through Y burden or better.

Metering circuits shall not be shared with other devices without the Cooperative's approval.

6.1.5 METERING ENCLOSURE

A metering enclosure or a pole mounted rack may be required to accommodate the additional CTs and/or PTs.

6.1.6 POWER QUALITY METERING

DER systems larger than 500 KW shall use a Power Quality (PQ) functionality capable revenue meter, that can provide the Cooperative with continuous monitoring and recording of the DER's PQ performance.

6.1.7 TRANSMISSION METERING & INTERCONNECTION REQUIREMENTS

DER projects required to meet transmission metering and interconnection requirements shall be coordinated with the Cooperative's transmission provider, WVPA.

All required transmission metering and interconnection requirements shall be met prior to DER energization and operation.

6.2 METERING INSTALLATION DIAGRAMS

6.2.1 ELECTRIC & GAS METER SET SEPARATION TYPICAL CLEARANCES

DER electrical installation shall meet applicable gas company electric and gas meter separation requirements. Typical separation clearances are shown for reference.

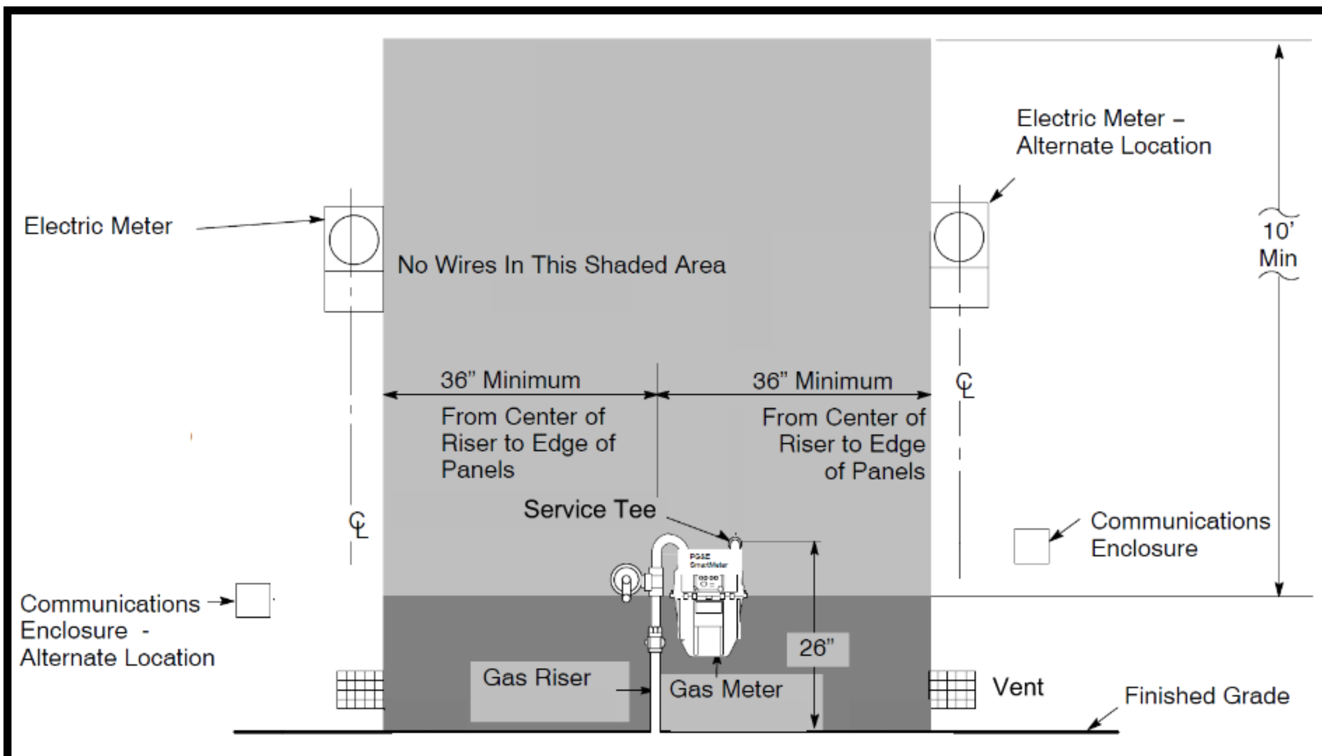


Figure 6 – Electric & Gas Meter Separation

6.2.2 RESIDENTIAL DER ONLY, NO ESS, OPTION 1

DER requiring a Power Production Meter shall meet the requirements below. Where Power Production Meter(s) are installed, a disconnecting means shall be located such that the inverter(s) can be serviced without de-energizing the production meter. A Combiner / Subpanel's breakers or a Visible Disconnect Device (VDD) are acceptable as this disconnecting means.

The locations of equipment shown below are intended to show relative positions between equipment. Drawing is not intended to show actual physical locations.

The NEC and the County / Municipal Electrical Inspector for your area may have requirements for your generation system that are beyond what is listed here. Please check with your local Inspector to make sure your plans meet their requirements.

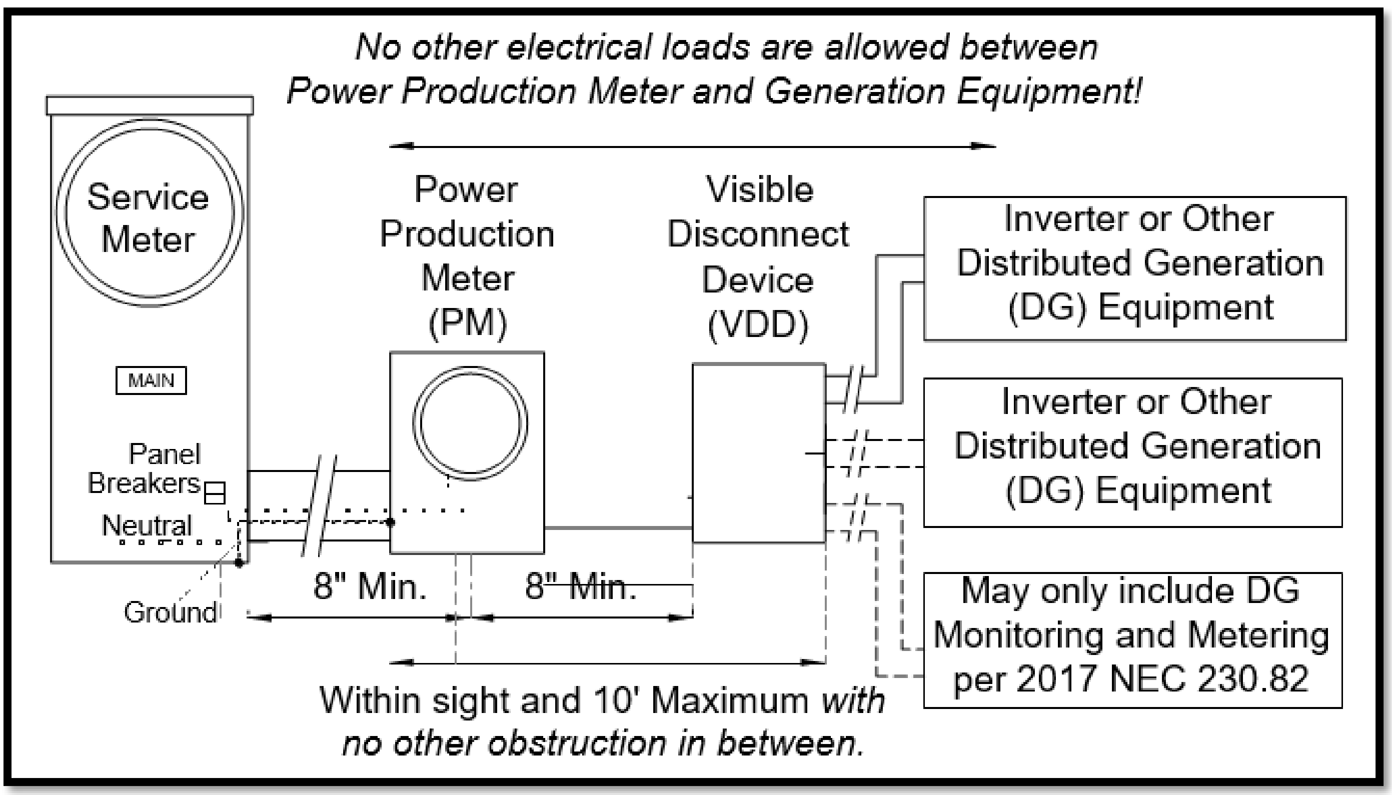


Figure 7 – Residential DER Only, No ESS – Option 1

6.2.3 RESIDENTIAL DER ONLY, NO ESS, OPTION 2

DER generation circuit is connected between Cooperative's Utility Service Meter and the Panel's Main breaker. A Fused Disconnect Switch needs to be installed between the Main Panel and the Power Production Meter (NEC 230).

Energy Storage Systems (ESS), such as batteries, that charge from utility AC power are considered LOADS, and these loads are not included in those permitted by NEC 230.82(5). As such, these storage systems may NOT be connected in this location. Energy Storage Systems that are configured to only charge from some other sources (such as the DC bus of a PV system) are considered generation and may connect in this location per NEC 230.82(6).

The locations of equipment shown below are intended to show relative positions between equipment. Drawing is not intended to show actual physical locations.

The NEC and the County / Municipal Electrical Inspector for your area may have requirements for your generation system that are beyond what is listed here. Please check with your local Inspector to make sure your plans meet their requirements.

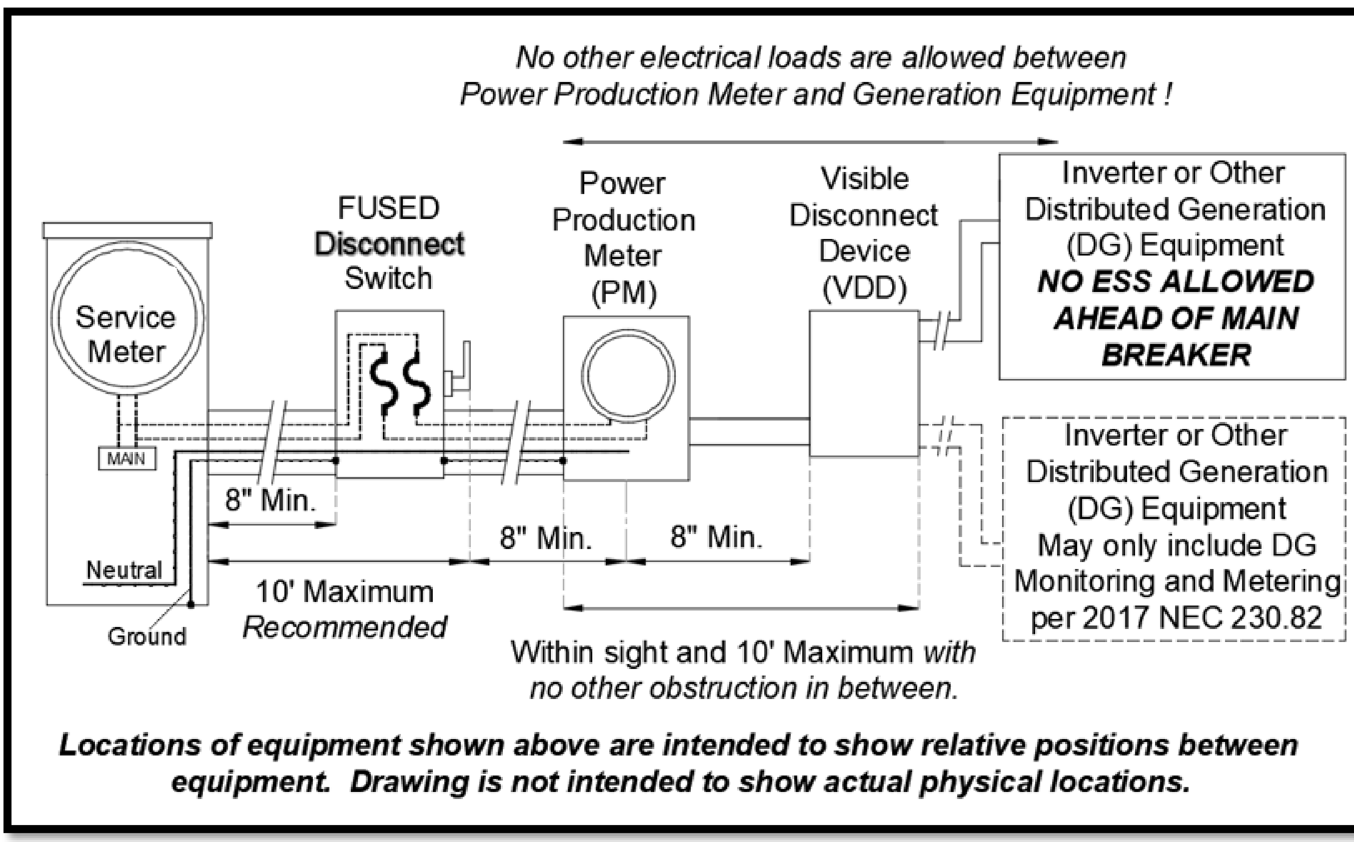


Figure 8 – Residential DER Only, No ESS – Option 2

6.2.4 RESIDENTIAL DER WITH ESS

DER generation connected to a breaker position in a Critical Load panel with an ESS connected to a separate breaker position in the Critical Load panel.

The locations of equipment shown below are intended to show relative positions between equipment. Drawing is not intended to show actual physical locations.

The NEC and the County / Municipal Electrical Inspector for your area may have requirements for your generation system that are beyond what is listed here. Please check with your local Inspector to make sure your plans meet their requirements.

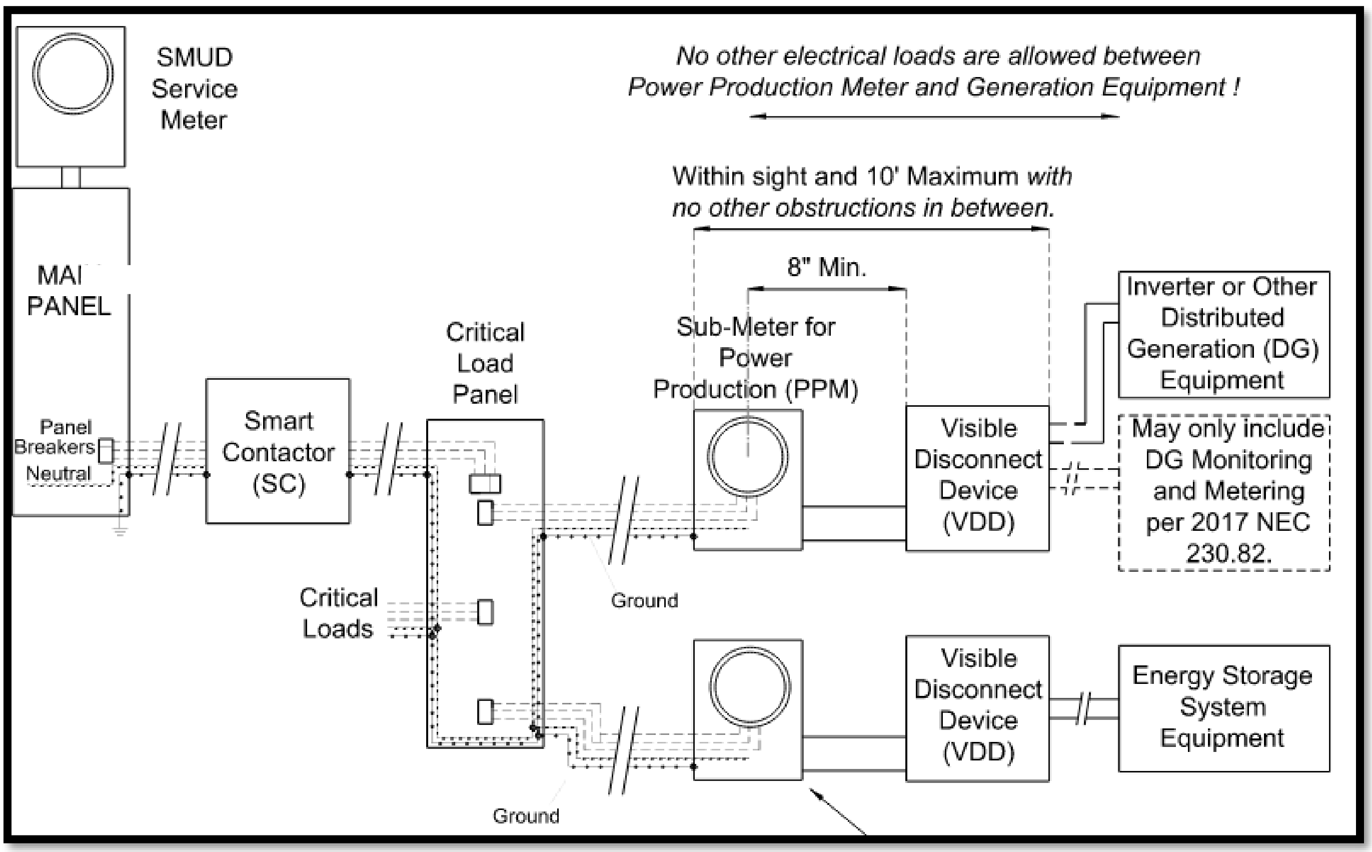


Figure 9 – Residential DER with ESS – Option 3

6.2.5 RESIDENTIAL DER WITH ESS

DER generation and ESS connected to the DC section of the same inverter.

The locations of equipment shown below are intended to show relative positions between equipment. Drawing is not intended to show actual physical locations.

The NEC and the County / Municipal Electrical Inspector for your area may have requirements for your generation system that are beyond what is listed here. Please check with your local Inspector to make sure your plans meet their requirements.

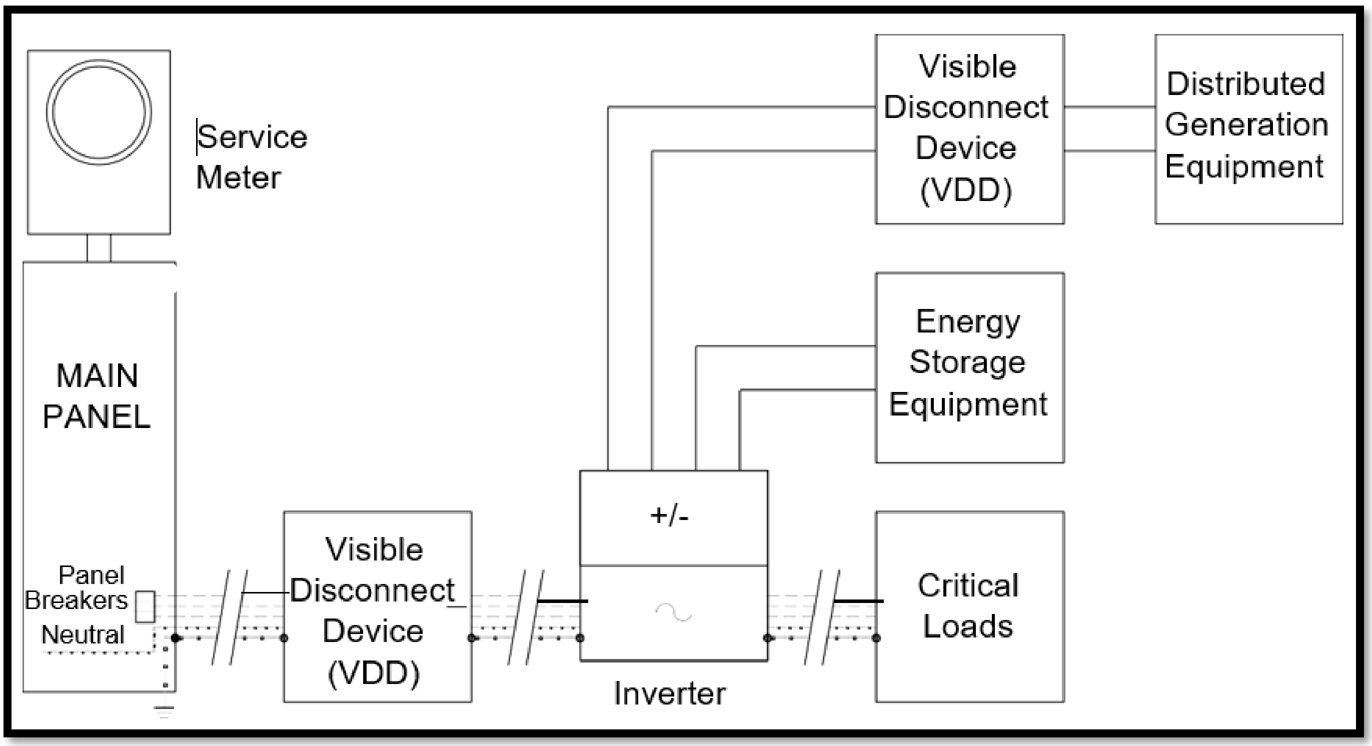


Figure 10 – Residential DER with ESS – Option 4

6.2.6 RESIDENTIAL DER WITH ESS

DER generation and ESS connected to the DC section of the same inverter.

The locations of equipment shown below are intended to show relative positions between equipment. Drawing is not intended to show actual physical locations.

The NEC and the County / Municipal Electrical Inspector for your area may have requirements for your generation system that are beyond what is listed here. Please check with your local Inspector to make sure your plans meet their requirements.

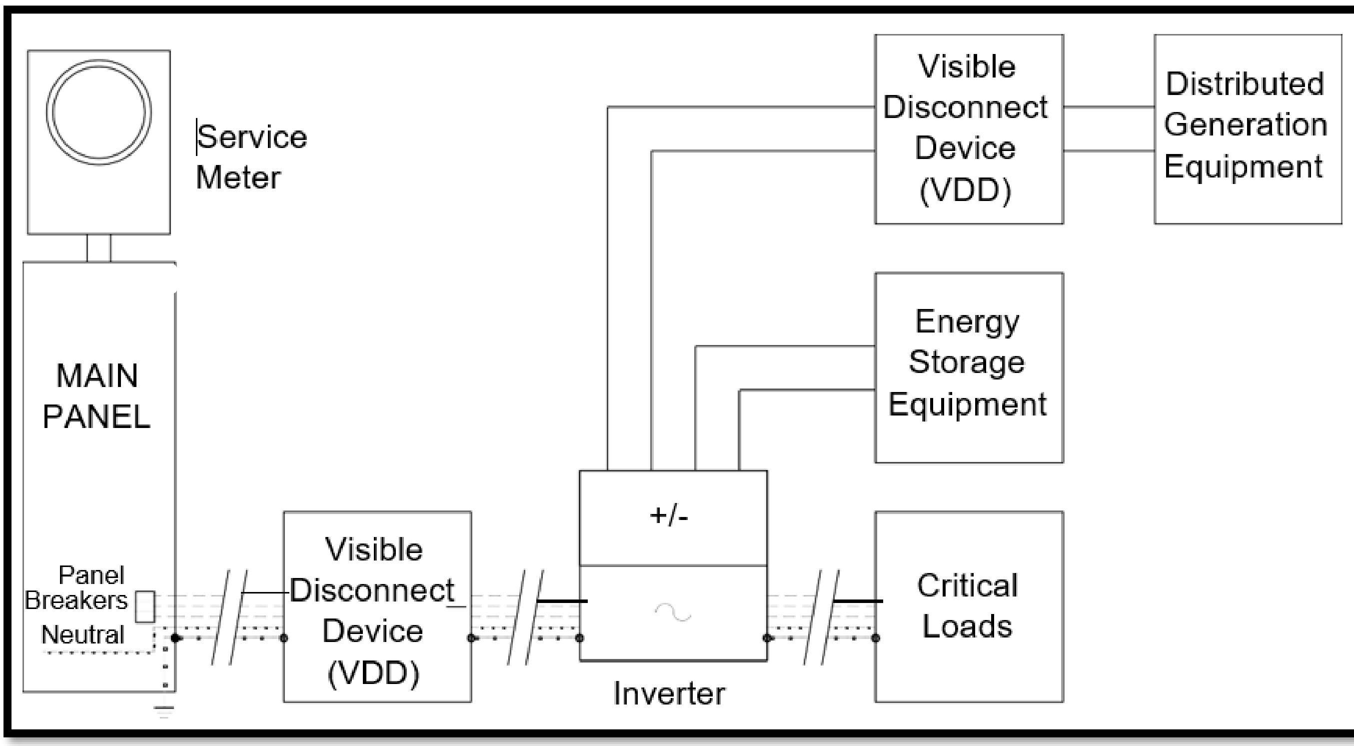


Figure 11 – Residential DER with ESS – Option 4

SECTION 7: TESTING AND COMMISSIONING

7.1 TESTING AND COMMISSIONING REQUIREMENTS

7.1.1 IEEE 1547.1-2020 TESTING AND COMMISSIONING

1. Testing and Commissioning Documentation
    a. The Producer shall develop and submit for review 100% design plans, permits, documentation, and actual relay settings and detailed testing plan to Cooperative for review prior to testing to avoid re-testing or duplicated testing efforts.
    b. Testing and commissioning per IEEE 1547-2018 Clause 11 – Test and Verification Requirements and IEEE 1547.1-2020 Clause 8 – DER evaluation and commissioning tests.
    c. Testing plan to demonstrate it will meet requirements as required in IEEE 1547.1-2020.
    d. Cooperative review of testing plan and relay settings requires 1-2 weeks. Testing will not be approved without prior Utility review and approval.
2. Site Inspection
    a. The Cooperative will inspect the DER site prior to performing Testing and Commissioning or DER operation.
    b. Inspection to confirm installation meets installation, design, and settings requirements.
3. Testing and Commissioning Performance
    a. Producer to perform Testing and Commissioning per approved Testing and Commissioning plan.
    b. At minimum, the commissioning process shall include commissioning tests specified by IEEE 1547-2018 Clause 11 – Test and Verification Requirements and IEEE 1547.1-2020 Clause 8 – DER evaluation and commissioning tests.
    c. Commissioning process to demonstrate the DER does not create adverse conditions for the Cooperative distribution system or other Cooperative members.
    d. Additional testing and requirements may be required for any intentional islands that energize Cooperative EPS facilities.
    e. The Site Controller shall be included in the Testing and Commissioning for sites with a Site Controller.
    f. Telemetry and SCADA systems shall be included in the Testing and Commissioning for sites with Telemetry and SCADA systems.
    g. DER Isolation Devices shall be included in Testing and Commissioning.
    h. Direct Transfer Trip (DTT) shall be included in the Testing and Commissioning for sites with DTT.
    i. Once Cooperative has approved the Testing and Commissioning plan, the Producer to provide 1-2 weeks of advance notice of testing timeframe to allow Cooperative to witness test Testing and Commissioning. Any required follow-up testing requires at least 2 business days of advanced notice.
    j. Testing and Commissioning not witnessed by Cooperative may have to be repeated.

4. Configuring DER Functional Settings
    a. DER facility's functional settings shall be developed in accordance with the default parameters listed in this document, or as otherwise specified in site-specific settings documented in an exhibit to the Customer's Interconnection Service Agreement.
5. Protective Relay Testing
    a. Responsibility of the Producer to provide qualified personnel to perform tests on the DER protective relaying and DTT prior to energizing from the Cooperative EPS.
    b. Producer to coordinate with Cooperative Protection and Control (P&C) personnel as needed to ensure both the DER and Cooperative facilities operate as expected.
    c. Configuration settings for protection settings shall be the settings previously provided by the Producer and approved by the Cooperative. These settings and configuration shall not be altered by the Producer without prior authorization from the Cooperative.
6. Witness Testing
    a. Before parallel operation with the Cooperative EPS but after completion of commissioning testing and inspections, witness testing may be required at the direction of the Cooperative.
    b. Witness Testing include, but are not limited to, the following:
        i. Cease to Energize
        ii. Trip Test
        iii. Open-Phase Detection
        iv. Anti-Islanding
        v. Reconnection Test
        vi. Load Rejection Overvoltage Test
        vii. Power Limit Test
        viii. Radio Frequency Interference Test
        ix. Current Harmonics Test
        x. Telemetry/SCADA Test
        xi. Primary Metering
        xii. Direct Transfer Tripping (When Applicable)
        xiii. Reverse Power Relay (When Applicable)
        xiv. Intentional Islanding Test (When Applicable)
7. As-Left Relay Settings
    a. Producer to submit as-left relay settings and testing and commissioning reports for Cooperative review.
    b. Testing and Commissioning to prove compliance with IEEE 1547.1-2020. Failure to establish IEEE-1547.1-2020 or Cooperative requirements shall require re-testing.
    c. <u>Cooperative review of testing plan and relay settings requires 1-2 weeks. Producer will not be approved for parallel operation without prior Cooperative review and approval of As-Left Relay Settings and Testing and Commissioning results.</u>
8. Permission to Operate

   a. Permission to energize for Testing and Commissiong purposes does not indicated permission to operate the DER in parallel with the Cooperative EPS. A formal Permission to Operate Notice shall be provided to the Producer upon successful completion of all Testing and Commissioning requirements.
9. Harmonic Content Recordings
   a. Recordings of current harmonic spectrum in accordance with IEEE Std 1547 and IEEE Std 519 at the output terminals of the total generator or inverter system package or at the low voltage side of the transformer that provides power to the facility from the Cooperative's Distribution System.
   b. Provide the Individual and total current spectrum 100%, 75%, 50% and 25% output of the unit.
10. Recommissioning
   a. Recommissioning of the DER facility may be required at any point in the lifecycle of the DER facility.
   b. The Cooperative may require DER recommissioning for reasons including, but not limited to:
      i. Changes to DER equipment, components, or protection and control settings
      ii. Changes in DER operating procedures or other facility characteristics
      iii. Changes to the Cooperative EPS
      iv. Abnormal DER performance
      v. Cooperative customer complaints
   c. The Cooperative shall notify the Producer of the need for recommissioning and determine the level of recommissioning tests on a case-by-case basis.
11. Periodic Testing
   a. Periodic testing may be required for the DER, as specified in the Interconnection Service Agreement or due to abnormal conditions.
   b. The Cooperative may conduct remote testing. Remote testing may include, but not be limited to:
      i. Communication Telemetry/SCADA
      ii. System Settings
      iii. Operating Profile
   c. Periodic Testing may require full compliance with IEEE 1547-2018 Clause 11 – Test and Verification Requirements and IEEE 1547.1-2020 Clause 8 – DER evaluation and commissioning tests. Producer to provide testing results for Cooperative review.
   d. Insufficient Periodic Testing results to be resolved in a timely manner by the Producer.
   e. Cooperative reserves the right to request Periodic Testing at any time.
   f. The Cooperative shall notify the Producer of the need for Periodic Testing on a case-by-case basis and provide adequate notice to the Producer for scheduling.
   g. The Cooperative shall coordinate with the Producer to minimize producer disruption to normal operations.

APPENDIX A: TYPICAL ONE-LINE DIAGRAM

ONE-LINE DIAGRAM REQUIREMENTS

The following are the One-Line Diagram Requirements for all DER projects. One-Line Diagrams must be developed by the Producer and submitted to the Cooperative as part of the DER Application:

1. Identify and properly locate all DER Equipment
    a. Identification must include manufacturer, model, and quantity of units
2. Producer's name, address and generation description listed in the Title Block
3. Generation type, quantity, and AC power output listed in the Title Block
4. GPS coordinates of the Point of Common Coupling and DER facilities
5. AC Disconnect Switch
6. Pre-Existing DER Equipment (When Applicable)
    a. Clearly differentiate and label pre-existing vs. new DER equipment
7. Level 1 DER Facilities, Block Diagram One-Line Diagram is acceptable
8. Equipment nameplate KW capacity, voltage, amperes, and phase rating
9. Transformer configuration and voltages
10. Metering
    a. Primary or Secondary
    b. Instrument Transformers
11. All site transformations, even those operating behind Primary Metering
12. Level 2 and Level 3 Facilities require licensed Professional Engineer stamp from State in which project is located.
13. Major Equipment Details
    a. PCC Location
    b. Ownership Demarcation
    c. Phase Identification
    d. Power Transformers
        i. Name/Designation
        ii. Manufacturer
        iii. Nominal KVA
        iv. Nominal Primary/Secondary/Tertiary Voltages
        v. Vector Diagrams
        vi. Winding Connections
        vii. Tap Settings
        viii. Impedance
        ix. Nameplate Drawing/Photo
        x. Test Reports – Both Positive & Negative Sequence Impedance
    e. Instrument Transformers
        i. Voltage
        ii. Current
        iii. Fusing
        iv. Phase Connections
    f. Capacitor Banks
        i. KVAR Rating
        ii. Fusing

        iii. Controls (When Applicable)
    g. Circuit Breakers
        i. Manufacturer
        ii. Continuous Rating
        iii. Interrupting Rating
        iv. Operating Times (Seconds/Cycles)
    h. Fuse
        i. Manufacturer
        ii. Type
        iii. Size
        iv. Speed
        v. Location