TECHNICAL SPECIFICATION MANUAL (TSM)

The Technical Specifications Manual for Interconnection of Distributed Energy Resources with Rochester Public Utilities - Area Electric Power System

ROCHESTER
PUBLIC UTILITIES
WE PLEDGE, WE DELIVER

Version:

Version #	Date	Notes
1	7/1/2021	Original adopted TSM
2	12/19/2023	Updated to include inverters with advanced functions of UL-1741 SB and IEEE 1547-2018

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1. Introduction

This Technical Specification Manual (TSM) has been developed as a companion document to the State of Minnesota Technical Interconnection and Interoperability Requirement (TIIR) for distributed energy resources interconnected to the distribution system. This Technical Specification Manual, also referred to as the TSM, is an accompanying document to the TIIR. The TSM contains additional technical requirements specific to the Area EPS Operator (Rochester Public Utilities).

Both the TIIR and the TSM are to be used with the adopted interconnection process. For municipal electric utilities in Minnesota, the interconnection process is generally known as the Municipal Minnesota Interconnection Process or M-MIP. Proposed DER interconnections submitted under the M-MIP relevant process adopted by the Area EPS shall be designed to comply with the technical requirements listed in the TIIR and Area EPS Operator's TSM.

The TSM is expected to be updated on a regular basis as DER technology and interconnection standards change. Interconnection Customers should confirm they are using the latest TSM version when designing their DER system. This TSM version incorporates the interim technical guidance listed in Annex C of the TIIR.

Substantial changes to existing DER systems, such as capacity additions or inverter changes, are required to be compliant with the latest version of the TIIR and TSM.

This document is not intended to describe every possible DER system interconnection or be a complete and inclusive list of all requirements. In addition to the requirements specified in this document the DER shall meet all applicable sections of the National Electric Code, National Electric Safety Code, applicable national standards (IEEE, ANSI, etc.), and the Area EPS (Rochester Public Utilities) Electric Service Rules in effect at time of initial application or major modification.

Rochester Public Utilities encourages individuals intending the interconnection of a DER with our system to complete an application prior to ordering DER equipment or completing any installation work to reduce the risk of additional costs or delays with the project. Applying for an interconnection will result in a design review by RPU engineering and operations staff. If the review identifies issues with the interconnection location, type or design, it is typically easier to resolve these issues prior to DER equipment been ordered.

The TSM document provides specific information about interconnecting a DER with Rochester Public Utilities electrical distribution system. The TSM is designed to provide technical requirements for renewable, storage, and fossil fuel DER systems specific to the Area EPS Operator and with an aggregate Nameplate Rating of 10 MW or less at the Point of Coming Coupling. The TSM applies to all DER installations that are capable of operating in parallel with Rochester Public Utilities distribution system for any period of time.

The IEEE 1547, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems, and IEEE 1547.1, IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems, are the primary standards for interconnection and interoperability requirements. All customer owned electrical work and equipment is required to comply with the National Electrical Code (NEC) and to be inspected by the local area electrical inspector prior to interconnection with Rochester Public Utilities. Rochester Public Utilities will require proof of compliance with the National Electrical Code and all of our applicable requirements prior to allowing the DER to interconnect with our system.

Rochester Public Utilities has the right to limit the maximum size of any DER and/or the number of DER systems interconnected, if the proposed DER system(s) adversely impacts the power quality or reduces the reliability to other customers connected to Rochester Public Utilities system. The interconnection of new DER facilities to the Rochester Public Utilities electric system must not degrade the existing Rochester Public Utilities protection or control schemes, nor lower the existing levels of safety and reliability for other customers.

This document only covers the technical requirements and does not cover the interconnection process from the planning process to the approval and construction of the project. The Minnesota Municipal Interconnection Process documents provide the procedures to follow and sample versions of the forms to submit. Rochester Public Utilities uses an on-line portal for completing and submitting interconnection applications. More information about the interconnection process and requirements can be found on the on line at www.rpu.org and information and application are processed through the on-line portal https://www.novapowerportal.com and selecting Rochester Public Utilities as from the drop down.

The earlier that Rochester Public Utilities gets involved in the interconnection process the less likely there will be last minute issues identified with interconnection requests.

1.1. General Information

1.1.1. Application of IEEE 1547-2018 Standards

The IEEE 1547-2018 standard has been approved and is available for use as the national standard for interconnection and interoperability of distributed energy resources with electric power systems.

All inverters which are part of a DER interconnection application filed on or after January 1, 2024, require certification under UL 1741SB standards. The settings presented in this document are required to be installed on all new inverters. The settings are presented in the EPRI Common File Format and are intended to conform to IEEE 1547-2018. Settings other than the values listed in this document may be required on a case-by-case basis to support unique interconnections. Any use of inverter settings other than those values listed in this document are subject to review and approval by Rochester Public Utilities.

Note: the use of UL 1741SA certified inverter(s) are not allowed for interconnections application filed on or after January 1, 2024.

DER systems installed under interconnection applications submitted prior to January 1, 2024 are allowed to continue to follow the technical requirements in force at the time of their interconnection, but existing inverter based DER systems which are Materially Modified1 shall utilize UL 1741SB inverters and the settings provided within this document.

1.1.2. References and Definitions

The references and the definitions from the IEEE 1547-2018 and Minnesota TIIR documents are applicable for this document.

1.1.3. Certified Inverter

An inverter is considered certified if it meets the requirements listed in attachment 5 of the Rochester Public Utilities approved Minnesota Municipal Interconnection Agreement (MMIA). The current standard for IEEE 1547 is the 2018 version. The testing standard IEEE 1547.1-2020 describes the testing required to certify interconnection equipment to the 2018 version of the IEEE 1547. Inverters are tested and certified under UL 1741. The older 2014 version of this certification is UL 1741SA. The current version which meets the IEEE 1741-2018 requirements is UL 1741SB. All interconnection applications received on or after January 1, 2024 require inverters which are certified by a national testing lab to UL 1741SB.

Inverters which are utilized in Vehicle-To-Grid (V2G) applications are required to be tested and certified to UL 1741SC. The technical requirements for electrically powered vehicles to back-feed the home or electrical grid are in the early stages of development and the technical interconnection requirements are not yet available; as such, the requirements are not included within the TIIR or the TSM. If you are considering a Vehicle-to-Grid (V2G) application / installation, please contact the Rochester Public Utilities Interconnection Coordinator DER@rpu.org for any additional technical requirements which maybe applicable.

DER systems installed under interconnection applications submitted prior to December 31, 2023, are allowed to continue to follow the technical requirements in force at the time of their interconnection application, but existing inverter based DER systems which are Materially Modified shall utilize UL 1741SB inverters and the settings provided within this document. Existing systems are encouraged, where reasonably possible, to upgrade their inverter settings to align with the updated advanced inverter interconnection settings in this version of the TSM. Please contact the Rochester Public Utilities Interconnection coordinator prior to any changes of inverter or relaying settings. To ensure our engineering models correctly reflect the current operation of any interconnected DER, the engineers need to know how each DER operational response settings are configured. Rochester Public Utilities will retest the interconnection as required, during normal business hours, without charge to the member.

1.1.4. Rochester Public Utilities Modifications

Depending upon the location of the interconnection, size of the DER and how the DER is operated, certain modifications and/or additions may be required to the existing Rochester Public Utilities electrical distribution system due to the addition of the DER. As part of the application and review process, any modifications required to the Rochester Public Utilities electrical distribution system will be identified along with the estimated costs which will be incurred by the DER applicant.

1.1.5. Distributed Energy Resource (DER) System Protection

Protection requirements in the TIIR and TSM are structured to protect the Area EPS, Area EPS customers, and the public. The protection of the DER and the Local EPS is solely the responsibility of the Interconnection Customer and is not addressed in these technical requirements. Additional protection equipment, beyond what is required within this TSM may be required to ensure proper operation of the DER. This is especially true while operating islanded from the Area EPS. Rochester Public Utilities does not assume responsibility for protection of the DER equipment or of any portion of the Local EPS.

1.1.6. DER Installations using Open Transfer Switch

For a DER installation to qualify as an open transition switch installation and the associated limited protective requirements, mechanical interlocks are required between the two source contacts. (Area EPS source and DER source) This is required to ensure that one of the contacts is always open and the DER can never be operated in parallel with the Area EPS. If the mechanical interlock is not present, the protection requirements are as if the switch is a closed transition switch that can parallel with the Area EPS. This requirement is due to the possibility that the solenoid operating a source contact could fail and parallel the DER with the Area EPS. Open Transition switches, with a mechanical interlock between the source contactors are exempt from submitting an interconnection application to the Area EPS. If there are any questions, please contact the Rochester Public Utilities DER coordinator.

1.1.7. Bulk Transmission System Requirements

The TSM document provides the requirements associated with the Rochester Public Utilities electric distribution system. Other than the advanced inverter grid support settings, this TSM document does not include any special requirements which may apply due to interaction of the proposed DER and the bulk transmission system.

Rochester Public Utilities electric distribution system is interconnected with the bulk transmission system and the interconnection and operation of the proposed DER may affect the transmission system. The Midcontinent Independent System Operator (MISO) has specific rules and requirements for DER, which are interconnected with the Rochester Public Utilities electric distribution system and are able to cause back feeding of the transmission system or otherwise affect the transmission system.

If the potential for affecting the transmission system is identified through the interconnection application process, Rochester Public Utilities together with the DER interconnection applicant will need to request studies by the area transmission provider and/or MISO to identify any transmission constraints or other transmission issues.

1.1.8. Aggregation and Coordination of DER Operations at Multiple Sites

Aggregated and coordinated operation of DER for the purpose of selling those services to a transmission market, is not allowed without written permission of the Area EPS. For example, the use of DER systems to provide frequency response or coordinated load control and sell that service to the MISO market, is not allowed on the Area EPS electric distribution system without written approval by the Area EPS.

1.1.9. Design and Maintenance of DER Facilities

Rochester Public Utilities review and approval of the interconnection of the DER system, is not a complete design and operational review of the DER system and does not relieve the DER Operator of its responsibility, to design, install, test, operate and maintain the DER system in a manner which is safe. The DER Operator is responsible to ensure that the DER system is designed, operated, and maintained so that it does not energize a deenergized portion of the Area EPS or injects inadvertent energy into the Area EPS which causes equipment damage, injuries or affects the reliable flow of electricity to other Rochester Public Utilities customers.

1.2 System Operation Type

The TSM addresses different types of DER systems by the way the DER system operates with the Area EPS. Additional information of the different types is available in the Appendix A.

1.3 Convention for Word Usage

Throughout this document, the word shall is used to indicate a mandatory requirement. The word should is used to indicate a recommendation. The word may is used to indicate a permissible action. The word can is used for statements of capability and possibility.

2. Abbreviations & Common Terms

AGIR	Authority Governing Interconnection Requirements
Area EPS Operator	The utility that operates the distribution system. In this document the Area EPS Operator is Rochester Public Utilities
BPS	Bulk Power System
CT	Current Transformer
DER	Distributed Energy Resource
M-MIP	Municipal Minnesota DER Interconnection Process
EPS	Electric Power System
ESS	Energy Storage System
Local EPS	Local Electrical Power System
MN DIA	Minnesota Distributed Energy Resource Interconnection Agreement
MN DIP	Minnesota Distributed Energy Resource Interconnection Process
NEC	National Electrical Code (National Fire Protection Standard 70)
NESC	National Electrical Safety Code (IEEE Standard C2)
PoC	Point of Distributed Energy Resource Connection
PCC	Point of Common Coupling
RPA	Reference Point of Applicability
RTO	Regional Transmission Operator
MN DER TIIR	Minnesota Distributed Energy Resource Technical Interconnection and Interoperability Requirements
TPS	Transmission Power System
TSM	Technical Specifications Manual

2.1. Key Terms

The terms used in this document are defined in the MN DER TIIR. For quick reference, the key terms are defined in this section.

Area Electric Power System (Area EPS): The electric power distribution system connected at the Point of Common Coupling. Rochester Public Utilities is the Area EPS for this TSM documents and the use of the terms Area EPA and Rochester Public Utilities are used interchangeably in this document.

Area Electric Power System Operator (Area EPS Operator): An entity that owns, controls, or operates the electric power distribution system that are used for the provision of electric service. Rochester Public Utilities is the Area EPS Operator for this TSM document.

Local Electric Power System (Local EPS): An EPS contained entirely within a single premise or group of premises. The Local EPS is typically the local electrical system in a house or business.

Point of Common Coupling (PCC): The point of connection between the Area EPS and the Local EPS. For residential customers with underground services this is typically the connection of the customers service lateral to the Rochester Public Utilities transformer or secondary pedestal. For overhead services this is typically the connection point of the customers service lateral at the overhead weatherhead.

Point of Distributed Energy Resources Connection (PoC): The point where a DER unit is electrically connected in a Local EPS and meets the requirement of the MN DER TIIR and this document exclusive of any load present in the respective part of the Local EPS.

Power Control: System that controls the output (production or discharging) and input (charging) of one or more DER in order to limit output, input, export and/or import.

Reference Point of Applicability (RPA): The location where the interconnection and interoperability performance requirements specified in the MN DER TIIR and this document apply. The RPA could be the PCC or the PoC, or another location which is defined in the operating section of the interconnection agreement.

3. Autonomous Smart Inverter Functions Default Activation Status

This version of the TSM has been harmonized with IEEE 1547A-2020 Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power System Interfaces for autonomous smart inverter functions.

Specific settings and requirements with advanced, interactive functions associated with IEEE 1547A-2020 are not included in this version of the TSM, but might in a future version pending further alignment with long range planning. DERs certified under UL 1741-2019 Certified Requirements Decision for Power Control System (CRD for PCS) are IEEE 1547A-2020 compliant and meet the updated TSM requirements.

Table 1 : Default Activation Status of Autonomous Functions

Function	Status
Constant Power Factor Mode	Disabled
Constant Reactive Power Mode	Disabled
Voltage-Reactive Power Control (Volt-Var)	Enabled
Active Power – Reactive Power Control (Watt-Var)	Disabled

Voltage-Active Power Control (Volt-Watt)	Enabled
Voltage Disturbance Ride-Through	Enabled
Frequency Disturbance Ride-Through	Enabled
Enter Service	Enabled
Anti-Islanding	Enabled

4. Performance Category Assignment

Performance Category Assignment is currently enforced. The required performance categories for DER based on the performance categories defined in IEEE 1547A-2020 are contained in the next two subsections. Rochester Public Utilities follows the TIIR for category assignment.

The DER shall use the IEEE 1547 default parameter settings for all capabilities and performance requirements of the applicable performance category unless otherwise specified by the TIRR, this TSM, or Rochester Public Utilities Engineering requirements from a project specific study.

4.1. Normal – Category A and B

The normal performance category specifies reactive power capability and voltage regulation performance requirements. Synchronous machine-based DER shall comply with normal performance Category A. Inverter-based DER shall comply with normal performance Category B. The Category B assignment supports Area EPS power quality in areas of high DER penetration and variable-generation DER.

Technology	**Normal Performance Category**
Inverter-based DER	Category B
Synchronous machine generation	Category A

4.2. Assignment of Abnormal Performance Category I, II or III

The abnormal performance category specifies trip and ride-through performance requirements. Synchronous machine-based DER shall comply with abnormal performance Category I. Inverter-based DER shall comply with abnormal performance Category III. The Category III assignment supports wide area and localized system stability in areas of high DER penetration and where nuisance tripping could cause voltage collapse or system overloads.

Technology	**Abnormal Performance Category**
Inverter-based DER	Category III
Synchronous machine generation	Category I

5. Reactive Power Capability and Voltage/Power Control Performance

This section provides the default and expected capabilities of a DER system on the Area EPS system. Using the advanced inverter functions as described in the following sections, the DER shall actively support the system voltage, but the DER shall not actively regulate the voltage at the PCC while in parallel with the Area EPS.

All DER which are being interconnected as part of an interconnection application received on or after January 1, 2024 are required to respond to abnormal conditions as documented in IEEE 1547-2018 with settings as established in the following sections. Where this document is silent, the DER shall use the IEEE 1547 default parameter settings for all capabilities and performance requirements of the applicable performance category. Material Modification1 of an existing DER installation will require conformance with the current technical standards and inverter settings.

The settings presented in this TSM are required to be installed on all inverter systems interconnecting in parallel with the Area EPS. The settings are presented in the EPRI Common File Format for DER Settings Exchange and Storage, also referred to as the Utility Required Profile (URP) format. Appendix H has examples of Utility specific settings (URP-SS) and installer Applied Settings (URP-AS) URP files. They are intended to conform with IEEE 1547-2018 and its amendment standard, IEEE 1547a-2020, and any use of inverter settings other than those listed in this document are subject to review and approval by Rochester Public Utilities. Note, the use of UL 1741 SA certified or older inverter(s) is not allowed by Rochester Public Utilities for DER interconnections submitted and filed on or after January 1st, 2024, for the readily available UL 1741 SB certified advanced inverters.

Please note that for all inverter replacements, whether due to age, condition, or otherwise, which currently are UL 1741 SB certified and configured to the requirements of this TSM, it is required that Rochester Public Utilities be notified of the model number and configuration (settings) which have been programmed into the replacement inverter to ensure a “like for like” replacement. Notification to Rochester Public Utilities is necessary and required so that it Engineers can correctly understand and model the response of all of the DER systems during disturbances to ensure safe and reliable operation of the Area EPS. If a “like for like” conversion is not possible or if the inverter(s) being replaced are legacy systems not certified to UL 1741 SB, then the interconnected customer will inform Rochester Public Utilities and request a Material Modification1.

For all Material Modification requests of DER system inverter(s), the use of advanced inverter(s) certified to UL 1741 SB with the settings outlined in this TSM is required, unless mutually agreed upon by both parties.

DER causing fluctuating and elevated voltages on the Area EPS beyond the acceptable ANSI C84.1 Range A levels must be mitigated. To assist in mitigation, reactive and active power control functions will be used.

Synchronous machine-based DER shall be capable of the following IEEE 1547A-2020 Category A voltage and reactive/active power control functions: constant power factor mode, voltage-reactive power mode, and constant reactive power mode.

Inverter-based DER shall be capable of IEEE 1547A-2020 Category B voltage and reactive/active power control functions: constant power factor mode, voltage-reactive power mode, active power-reactive power mode, constant reactive power mode, and voltage-active power mode.

Only one reactive power control function is enabled at a time, as indicated in Table 1. In general, reactive power control functions inject or absorb VARs to control voltage for normal Area EPS conditions and active power control functions reduce active power output for abnormal Area EPS conditions. If enabled, the voltage-active power control function reduces active power output while one of the reactive power control functions injects or absorbs VARs.

Inverter-based energy storage systems are required to operate in 4-quadrants. Energy storage DER shall comply with this section of the TSM, except the “active power output” language in IEEE 1547A-2020 Section 5 becomes “active power output and input”.

Under the terms of the Operating and Maintenance Requirements Area EPS Operator may provide notice of a change to a voltage and reactive/active power setting, and the DER needs to implement this change. The DER must apply the then-current reactive and active power setting. The then-current setting is the value set in the Operating and Maintenance Requirements (without any notice being sent by Area EPS Operator changing that value), or is the value set in the most recent notice from Area EPS Operator changing the value.

5.1. Constant Power Factor Mode

The use of constant power factor control has been disallowed/disabled and instead active support of the system voltage, using the advanced functions outlined in IEEE-1547-2018, are being utilized. These functions are designed to reduce high and low voltage due to energy exchange by the DER system. Systems submitted prior to January 1, 2024, may continue to use the settings in the previous version of the TSM such as constant power factor, which were the requirements at the time the application for interconnection of the system was made.

5.2. Constant Power Factor

The Area EPS Operator requires the settings for constant power factor to be disabled, unless otherwise specified in the Interconnection Agreement.

5.3. Voltage-Reactive Power Control

The settings for Voltage-Reactive Control will be enabled unless otherwise specified in the Interconnection Agreement.

The Voltage-Reactive Power mode default settings shall be set to the IEEE 1547A-2020 default settings as shown in Table 2 unless the results of a system impact study determine other settings are required and specified in the Interconnection Agreement.

Table 2: Voltage-Reactive Power Default Setting

Voltage-Reactive Power Parameters	Default Settings	
	Synchronous Machine-Based DER	**Inverter-based DER**
V_{Ref}	V_N [a]	V_N [a]
V_1	0.09 V_N	.92 V_N
V_2	V_N	.98 V_N
V_3	V_N	1.02 V_N
V_4	1.1 V_N	1.08 V_N
Q_1 [b]	25% of nameplate apparent power rating, injection	44% of nameplate apparent power rating, injection
Q_2	0	0
Q_3	0	0
Q_4	25% of nameplate apparent power rating, injection	44% of nameplate apparent power rating, injection
Open Loop Response Time	10 s	5 s

[a] V_N is assumed to be set at DER nominal operating voltage (Example 120, 208, 240, 277, 480 Volts)

[b] The DER reactive power capability may be reduced at lower voltage

All DERs shall autonomously adjust the reference voltage with VRef being equal to the low pass filtered measured voltage. The time constant shall be set to 300s.

5.4. Voltage – Active Power Control

The Area EPS Operator requires the settings for Voltage-Active Power control to be enabled for IEEE 1547A-2020 Category B systems, unless otherwise specified by the Interconnection Agreement. The default in IEEE 1547A-2020 is to disable Voltage-Active Power Controls, therefore DER equipment may require a settings change.

The Voltage-Active Power mode default setting shall be set to the IEEE 1547A-2020 Category B default setting as shown in Table 3 unless otherwise specified by the system impact study.

Table 3: Voltage – Active Power Control Default Settings

Voltage – Active Power Parameters	Default Settings
V_1	$1.06\ V_n$[a]
P_1	P_{rated}
V_2	$1.1\ V_n$
P_2 (applicable to DER that can only generate active power)	The lesser of $0.2\ P_{rated}$ or P_{min}[b]
P'_2 (applicable to DER that can generate and absorb active power)	0[c]
Open Loop Response Times	10 s

[a] V_n is assumed to be set at DER nominal operating voltage (Example 120, 208, 240, 277, 480 Volts)

[b] Pmin is the minimum active power output in p.u. of the DER rating.

[c] Prated is the maximum amount of active power that can be absorbed by the DER. ESS operating in the negative real power half plane, through charging, shall follow this curve as long as available energy storage capacity permits this operation.

5.5. Active – Reactive Power Control (Watt – Var)

The Area EPS Operator requires the settings for Active Power – Reactive Power Control to be disabled.

5.6. Constant Reactive Power Control

The Area EPS Operator requires the settings for Constant Reactive Power Control to be disabled.

6. Response to Abnormal Condition

All DER which are being interconnected as part of an interconnection application received on or after January 1, 2024 are required to respond to abnormal conditions as documented in IEEE 1547-2018 with settings as established in the following sections. The following settings are based upon the as modified IEEE 1547-2020 requirements.

Inverter-based DER shall be able to meet the requirements of IEEE 1547A-2020 Abnormal Performance Category III for response to abnormal conditions. Tables 13 and 16 and Figures H.7 – H.9 of IEEE 1547A-2020 are applicable for abnormal voltages and Tables 18 and 19 and Figure H.10 of IEEE 1547A-2020 are applicable for abnormal frequencies.

Synchronous machine-based DER shall be able to meet the requirements of IEEE 1547A- 2020 Abnormal Performance Category I for response to abnormal conditions. Tables 11 and 14 and

Figure H.7 – H.9 are applicable for abnormal voltages and Tables 18 and 19 and Figure H.10 of IEEE 1547A-2020 are applicable for abnormal frequencies.

If exceptions apply per IEEE 1547A-2020 Section 6.4.2.1 and 6.5.2.1 the voltage and frequency ride-through requirements specified in this section do not apply and DER may cease to energize the Area EPS and trip without limitations.

6.1. Voltage Ride-Through and Tripping

The DER shall trip for any abnormal voltages outside of these parameters. The following table lists the clearing time for the DER system for over and undervoltages. If able, the system shall ride through the disturbance until these values are reached.

Table 4: Synchronous DER Response (shall Trip) to Abnormal Voltages

Shall Trip – Synchronous DER		
Shall Trip Function	**Default Setting**	
	Clearing time (s)	**Voltage (per unit ofnominal voltage)**
UV2	0.32	0.45
UV1	5.0	0.70
OV1	2.0	1.10
OV2	0.16	1.20

Table 5: Inverter DER Response (shall trip) to Abnormal Voltages

Shall Trip – Inverter DER		
Shall Trip Function	**Default Setting**	
	Clearing time (s)	**Voltage (per unit of nominal voltage)**
UV2	0.32	0.45
UV1	5.0	0.70
OV1	2.0	1.10
OV2	0.16	1.20

6.2. Frequency Ride-Through and Tripping

The DER shall conform to the ride-through requirements for the applicable Abnormal Operating Performance Category. The IEEE 1547 default parameters shall be implemented by the DER Operator for the applicable performance category. Table 6 shall be followed unless specified by the RTO.

Table 6: DER Response (shall trip) to Abnormal Frequencies of DER Abnormal Operating Performance Category I, Category II, and Category III

Shall Trip Function	Default Setting	
	Clearing time (s)	Frequency (Hz)
UF2	0.16	56.5
UF1	300.0	58.5
OF1	300.0	61.2
OF2	0.16	62.0

The DER shall conform to the Rate of Change of Frequency (ROCOF) ride- through requirements for the applicable Abnormal Operating Performance Categories. The IEEE 1547 values shown in the following table shall be implemented by the DER Operator for the applicable performance category.

Table 7: Rate-of-Change-of-Frequency (ROCOF) Ride Through Requirements for DER of Abnormal Operating Performance Category I, Category II, and Category III

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

The DER shall conform to the frequency-droop requirements for the applicable Abnormal Operating Performance Categories. The IEEE 1547 values shown in the following table shall be implemented by the DER Operator for the applicable performance category.

Table 8: Frequency Droop Requirements

Parameter	Default Settings[a]
k_{OF}, k_{UF}	0.05
$T_{response\ (small\ signal)}$(s)	5
db_{OF}, db_{UF} (Hz)	0.036

DER systems designated by authority having jurisdiction as emergency, legally required, or critical operations power systems providing backup power to hospitals, fire stations or other emergency facilities defined by applicable industry code, shall be exempt from the ride-through requirements of this section.

6.3. Dynamic Voltage Support

The Area EPS operator requires that Dynamic Voltage support is disabled at this time.

7. Protection Requirements

Protective devices are required to permit safe and proper operation of the Area EPS while interconnected with DER systems. Examples of the protection requirements for different types of DER interconnections are shown in Appendix A. The figures in Appendix A are for typical installations and may not fit all possible configurations. The specific protection requirements for interconnection will depend upon the DER's size and type; the number of units; Area EPS configuration and characteristics; the operating modes of the DER; and the location of the proposed DER interconnection on the Area EPS.

An increased degree of protection is required for increased DER size. As DER capacity size increases the greater magnitude of short circuit currents and the potential impact to system stability can occur from the DER installations. Medium and large DER systems will require more sensitive and faster protection to minimize damage and ensure safety.

The interconnection of a new DER facility to the Area EPS shall not degrade any of the existing Area EPS protection and control schemes nor lower the existing levels of safety and reliability to other entities interconnected as loads to the Area EPS.

The Interconnection Customer shall provide protective devices and systems to detect the voltage, frequency and harmonic levels as defined in the IEEE 1547 during periods when the DER is operated in parallel with the Area EPS. The Interconnection Customer shall be responsible for the purchase, installation, and maintenance of these devices.

RPU primarily uses SEL protective relays and communication devices. In installations where the DER protection devices shall be able to interface with RPU's SEL protective relays, SEL's Mirrored Bits communications should used. (example: Direct Transfer Trip of DER protection devices).

7.1. Requirement of Utility AC Disconnect

A Utility AC Disconnect for use by the Area EPS and furnished by the DER Operator is required on all DER systems to safely isolate the DER from the Area EPS. The disconnect shall:

- Provide a visible air-gap. The visible open needs to be viewable without unbolting covers or removing other hardware.
- Be an AC rated device, UL or National Electrical Manufacture's Association approved.
- Be manually operable by one person.
- Be lockable in the open position.
- Be sized for adequate ampere capacity.
- Be located outside where it is continuously readily accessible, with unescorted access to the Area EPS.
- Access shall be free of obstructions from other equipment, devices, vegetation, etc.
- Does not require fasteners to be removed to access the disconnect handle.

- Be gang operated so that operation of one switch handle opens and closes all energized conductors simultaneously.
- Not interrupt neutral conductors.

The Utility AC Disconnect may be the same disconnecting means required by the NEC if the disconnect meets all the other Area EPS Operator requirements listed in this section.

7.1.1. Location of Utility AC Disconnection

The Utility AC disconnect used by the Area EPS Operator to safely isolate the DER from the Area EPS shall be located within 10 feet of the revenue meter. If the Utility AC Disconnect is proposed to not to be located within 10 feet of the revenue meter, the proposed location will be identified on the site drawing submitted to the Area EPS Operator with the Interconnection Application. The Area EPS Operator reserves the right to withhold approval for the placement of the Utility AC Disconnect in a location which is not within 10 feet of the revenue meter. If approved location is not located within 10 feet of the revenue meter, a permanently affixed placard meeting NEC requirements, as discussed in Section 12, shall be located at the revenue meter indicating the Utility AC Disconnect location. The placard shall achieve this with a mapped representation of the property, with the location of the AC disconnect denoted.

The Utility AC Disconnect shall be located between the Area EPS Operator owned equipment and the DER. For example, if a production meter is present, the disconnect shall be between the production meter and the DER. If the system voltage is greater than 240 VAC then the disconnect shall be located on the Area EPS Operator side of the production meter.

The location of the Utility AC Disconnect shall be subject to all of the height, clearance requirements, and restrictions placed on meter locations in the Area EPS most recent Electric Service Rules and Regulations.

7.2. Protection Coordination

7.2.1. Secondary Services

In general, overcurrent protection requirements shall meet the requirements of the NEC for DER interconnection that occur behind the Area EPS Operator’s revenue meter. All electric services are required to have main service protection furnished by the customer immediately after the main service meter. Double-lugging meters is allowed with approved kits as long as all NEC conductor protection requirements are met.

7.2.2. Primary Services

The first protective device on the DER customer’s side of the revenue meter shall coordinate with the Area EPS Operator’s protective device. Protection coordination studies are required for interconnections to the primary system. The protection study shall be completed by the Interconnection Customer and reviewed and approved by the Area EPS Operator prior to interconnection and energization.

7.2.3. Coordination with Area EPS Automatic Reclosing Schemes

The Area EPS Operator may have automatic reclosing schemes designed into the Area EPS to attempt to prevent transient faults from becoming a long-term outage. The automatic reclosing scheme will de-energize a portion of the Area EPS and re-energize the same section of Area EPS in a short period of time, less than one second, often clearing the fault on the Area EPS.

Automatic reclosing on the Area EPS can potentially damage rotating DER generation, both synchronous and induction DER generators, operating in parallel with the Area EPS. The addition of DER shall not alter the standard auto restoration schemes designed in the Area EPS. The Interconnection Customer is responsible for protecting the DER facility’s equipment from damage due to the automatic or manual reclosing, faults or other disturbances on the Area EPS. Contact the local EPS to identify reclosers and associated settings that may require affect operation of the DER.

7.3. Grounded Wye-Wye Protection Requirements

The following protection requirements are for grounded wye-wye DER system interconnections. Additional protection requirements may apply for DER systems which are not grounded wye-wye or do not utilize a grounded wye-wye transformer as part of the DER interconnection system design. Non-exporting DER systems that operate in parallel with the Area EPS have the same requirements as that of any other DER interconnection.

7.3.1. General Relay Information

For DER systems which are smaller than 250 kW and utilize a certified inverter(s) for interconnection, a Professional Electrical Engineer is not required to review, test and approve the protective functions or settings of the inverter. For all other DER systems to be interconnected with Area EPS, the protective functions and relay setting shall be reviewed and approved by a Professional Electrical Engineer registered in the State of Minnesota.

Prior to energization or interconnection of the DER with the Area EPS, a copy of the proposed protective relay settings shall be supplied to the Area EPS Operator for review and approval. The Area EPS Operator shall review the protective relay settings to ensure proper coordination between the DER and the Area EPS. The proposed protective relay settings shall be provided to the Area EPS Operator with time allotted to allow for review, coordination, implementation and functional testing of the protective system including any requested modifications.

7.3.2. Non-Certified Inverters

The use of inverters that have not been tested by a Nationally Recognized Testing Laboratory (NRTL) and certified to meet the UL 1741 performance requirements are not allowed by the Area EPS Operator as an acceptable design of the DER system.

7.3.3. Relaying

All equipment providing relaying functions shall meet or exceed ANSI/IEEE Standards for protective relays, i.e., C37.90, C37.90.1 and C37.90.2.

Required relays that are not “draw-out” cased relays shall have test plugs or test switches installed to permit field testing and maintenance of the relay without unwiring or disassembling the equipment.

Three-phase interconnections shall utilize three-phase power relays, which monitor all three phases of voltage and current, unless so noted in the Appendix A diagrams.

All protective relays must have DC power supplies powered by station class batteries and charging system. The battery system shall be equipped with a DC-undervoltage detection alarm or be monitored by a continuous monitoring facility. For DER larger than 250 kW, the DC voltage level must be provided to the Area EPS Operator’s SCADA system.

All relays shall be equipped with setting limit ranges at least as wide as specified in IEEE 1547, and meet other requirements as specified in the Area EPS interconnect study. Setting limit ranges are not to be confused with the actual relay settings required for the proper operation of the installation. At a minimum, all protective systems shall meet the requirements established in IEEE 1547.

See Appendix B for specific information regarding the types of relaying.

7.3.4. DC Power for Protection Devices

All relays and other devices which require external power to operate must be supplied by a DC battery system that can maintain power to the protective device for a minimum of 8 hours during a complete power outage. The DC battery charger shall be able to be powered by the DER if power from the Area EPS is lost. The DER shall be blocked from reconnecting to the Area EPS if the adequate DC power is not available to the protective devices.

The DC battery system shall be capable of monitoring and alarming for certain conditions related to voltage levels and charging ability. The DC battery system shall be monitored for DC voltage levels and have the capability of alarming if DC voltage reaches levels that cannot allow operation. The DC battery system shall also alarm if the battery charging system fails.

The alarms from the DC battery system shall be monitored by the Interconnection Customer. If the alarms are not monitored continuously, the alarm shall be audible or include a flashing light before complete loss of DC battery voltage.

7.3.5. Open Phase Detection

For non-inverter based DER, or inverter-based DER that opt not to use the onboard protective functions of the inverter for open-phase detection, either due to DER design configurations that render the detection method invalid or other reason, special consideration will need to be given to the methodology used to detect and trip for an open phase event.

Typical inverter-based configurations that require additional relaying include:

- Configurations with zig-zag or grounded wye-delta grounding banks.

- Configurations with delta windings on onsite transformers.

As required by IEEE 1547, all DER must detect open phase conditions at their RPA when their output is as low as 5% of their rated output, or, if not capable of producing apparent power at 5% of its rated output, at the lowest output the DER can continue producing apparent power.

The Area EPS Operator does not recommend a specific method for detecting an open phase condition, as there are many acceptable methods. Positive-sequence phase balance, zero-sequence detection and undervoltage relaying are known to be deficient protective schemes and will not be accepted for the purpose of detecting and tripping of an open phase.

- Positive-sequence phase balance and zero-sequence detection must set their pickup levels above the inherit imbalance on the Area EPS to avoid nuisance tripping. This pickup level will often be too high to allow the protective system to identify an open phase condition when the DER is at 5% output.
- Loss of phase via undervoltage relaying detection is inadequate for identifying an open phase condition. Ground banks and delta winding, present on both the DER site and on the larger Area EPS, may reconstruct voltage at the open point of the RPA.

7.3.6. Single-phase on Multiphase Services

The total nameplate rating for an individual single-phase inverter on a multi- phase system cannot exceed 10% of the distribution transformer rating that is supplying the service.

Multiple single-phase DER systems which are connecting to a multi-phase service to form a three-phase generation source, must provide protection to allow sensing and tripping of the entire DER system upon loss of a single individual phase.

DER systems which are connecting to an existing two-phase Open Delta-Wye or Open Wye-Delta secondary must be single-phase or the voltage of the service shall be converted to 120/208 or 277/480 volts.

7.4. Interconnection Transformers Connections

Interconnection Customer-owned transformers that are part of the DER system shall fall under one of the following connections.

7.4.1. Wye-Wye Transformer Connections

A Wye-Wye transformer is the preferred transformer connection. Both the primary and secondary of the transformer must be grounded. Do note, this transformer connection is subjected to harmonics from the Area EPS and the DER must be designed to limit the harmonic output from the DER system to below IEEE standard levels.

7.4.2. Wye-Delta Transformer Connections

The wye side of the transformation is required to be grounded.

High side voltage monitoring to sense single-phase faults on the primary side of the transformer is required.

All issues with zero sequence injections into the Area EPS from the Grounded Wye winding shall be addressed. Documentation is required to be provided to the Area EPS Operator for review.

7.4.3. Delta-Wye Transformer Connections

This transformer configuration is not allowed for interconnection of a DER system.

7.5. Grounding

For Interconnection Customer provide transformers that are part of the DER system, the transformer grounding shall properly interconnect with the grounding of the Area EPS.

7.5.1. Requirement of Grounding Transformer

Grounding transformers are not required by the Area EPS Operator.

7.5.2. Wye-Wye Interconnection

For Wye-Wye transformer configurations both the primary and secondary side of the transformer shall be grounded. The DER must also include an appropriately sized ground bank or the generator's neutral must be adequately grounded.

7.5.3. Wye-Delta Interconnection

For Wye-Delta transformer configurations the wye side is required to be grounded.

7.5.4. Delta-Wye Interconnection

Delta-Wye transformer configurations are not allowed by the Area EPS Operator for DER system interconnected to the Area EPS.

8. Operations

8.1. Periodical Testing & Record Keeping

The Interconnection Customer shall notify the Area EPS Operator prior to any of the following events occurring:

i. Protection functions are being adjusted after the initial commissioning process.

ii. Functional software or firmware changes are being made on the DER.

iii. Any hardware component of the DER is being modified in the field or is being replaced or repaired with parts that are not substitutive components compliant with this standard.

iv. Protection settings are being changed after factory testing.

Prior to modifications to the DER triggering reverification, the Interconnection Customer shall notify the Area EPS Operator's interconnection coordinator, by emailing DER@rpu.org. The email should include details about the proposed modification and the DER contact to communicate with for additional information, if needed. The Area EPS Operator strongly encourages using the DER Alteration Notification form shown in Appendix F to provide the necessary information. Any of the above events may be cause for requiring reverification of the interconnection and interoperability requirements as stated in the MN DER TIIR Section 14.5.

All interconnection-related protection and control systems shall be periodically tested and maintained, by the Interconnection Customer, at intervals specified by the manufacturer or system integrator and shall not exceed five years. Periodic test reports and a log of inspections shall be maintained by the Interconnection Customer and made available to the Area EPS Operator upon request. The Area EPS Operator shall be notified prior to the testing of the protective and control systems to witness the testing if so desired. The testing procedure for re-test should be a functional test of the protection and control systems.

The Area EPS Operator requires any system that depends upon a battery for trip/protection power shall be checked and logged once per month for proper voltage. For DER systems with nameplate rating of 1,000 kW or more, continuous monitoring of the DC battery voltage is required. Logging of all periodic inspection is recommended.

8.2. O&M Agreements

For DER systems that operate in parallel with a capacity of 40 kW or greater, the Operating and Maintenance Requirements section of the Interconnection Agreement is established. The Operating and Maintenance Requirements section of the Interconnection Agreement covers items that are necessary for the reliable operation of the Local and Area EPS and are unique to each DER. The items included as Operating Requirements shall not be limited to the items shown on this list:

i. Operational requirements, settings, and limits for DER when the Area EPS is in a normal condition

ii. Operational requirements, settings, and limits when the Area EPS is in an abnormal condition due to maintenance, contingencies, or other system issues

iii. Permitted and disallowed ESS Control Modes

iv. BPS or TPS limitations and arrangements that could impact DER operation

v. DER restoration of output or return to service settings and limitations

vi. Response to control or communication failures

vii. Performance category assignments (normal and abnormal)

viii. Dispatch characteristics of DER

ix. Notification process between Interconnection Customer and Area EPS Operator

x. Right of Access

The following is a list of typical items that may be included as Maintenance Requirements. The items are not to be limited to the items included in this list:

i. Routine maintenance requirements and definition of responsibilities

ii. Material modification of the DER that may impact the Area EPS

8.3. System Voltage

Operation of the DER shall not cause the voltage at the PCC to go outside of ANSI Range A under normal operations. Operation of the DER that causes voltages to go outside the ANSI Range A voltage values may be cause for disconnection until the reason can be identified and corrected.

For reference, ANSI C84.1-2020 defines Service Voltage as Range A. Table 9 contains Range A values for common RPU voltages:

Table 9: Service Voltage Limits

Nominal System Voltage	Maximum Service Voltage	Minimum Service Voltage
120 (2-wire)	126	114
120/240 (3-wire)	126/252	114/228
208Y/120 (4-wire)	218Y/126	197Y/114
480Y/277	504Y/291	456Y/263
13,800Y/7,970	14,490Y/8,370	13,460Y/7,770

Any sudden voltage changes caused by the DER which adversely affect other interconnected entities to the Area EPS shall not be allowed. It is the DERs responsibility to resolve adverse voltage changes caused by the operation of their DER. The Area EPS Operator will work cooperatively with the DER to identify possible solutions.

8.4. Power Ramp Rates

8.4.1. Overview

The ability for the Area EPS to respond to large changes in increasing or decreasing demand for energy depend upon the PCC with the Area EPS. The ratio of generation to load on the Area EPS correlates with the potential of voltage disturbances on the Area EPS as generation is abruptly added or removed from extended parallel operation with the Area EPS. In some cases, if the step change is large enough, Area EPS protection devices may operate under the assumption a fault has occurred with the abrupt change in voltage. The larger the amount of load or generation added or removed from the Area EPS, the greater the chance of creating operational problems for other entities interconnected on the Area EPS.

As part of the interconnection study, the Area EPS Operator will review the potential for step changes of 3% or greater in load or energy production that can create operational problems on the Area EPS. It is the Interconnection Customer's responsibility to review for potential Local EPS issue which may result from block changes in load or generation from the DER.

8.4.2. Power Ramp Rates Requirements

DER systems shall not cause the Area EPS voltage to be outside of ANSI Range A voltage levels. Block loading or off-loading of the DER generation that causes voltage step changes of 3% or greater on the Area EPS is not allowed.

8.5. Enter Service

Enter Service is the period where the DER begins operation with an energized Area EPS. Enter Service may be part of daily operation of the DER or occur after a power outage on the Area EPS. The method the DER uses to Enter Service is important to the reliability and performance of the Local EPS and the Area EPS. All DER systems shall not energize and parallel with the Area EPS unless applicable voltage and system frequency are within the ranges specified in Table 10.

Table 10: DER Enter Service Criteria Ranges

Enter Service Criteria		**Default settings**
Applicable voltage within range	Minimum Value	≥ 0.917 p.u.
	Maximum Value	≤ 1.05 p.u.
Frequency within range	Minimum Value	≥ 59.3 Hz
	Maximum value	≤ 60.5 Hz

A minimum delay of 300 seconds from when the DER ceases operations is required before resychronization. The DER shall parallel and synchronize with the Area EPS is accordance with IEEE 1547. Upon synchronization, the duration of enter service period shall use a linear ramp rate of 300 seconds to full operations. Randomization of enter service may be used instead of linear ramping of the DER system upon mutual agreement between the DER Operator and the Area EPS Operator.

8.5.1. DER without ESS

For DER that does not include ESS, possible methods which may be required include:

- The delay time for re-energization of the DER after an outage may be increased.
- The DER may be required to stagger the re-energization of inverters.
- Multiple transfer switches may be required to divide up the blocks of load transferred to the DER.

8.5.2. Energy Storage Systems

ESS shall be set to an intentional delay of a minimum of 300 s, (5 minutes), before initiating recharging of the ESS. If possible, the Area EPS Operator would prefer the ESS ramp up the recharging level from 0 – 100% over the first ten-minute time period of initial recharging. ESS larger than 250 kW may be required to have a specific intentional delay prior to enter service. The specific delay will be documented in the Operating and Maintenance Requirements section of the Interconnection Agreement.

9. Power Control Systems

9.1. General

Power Control: System that controls the output (production or discharging) and input (charging) of one or more DER in order to limit output, input, export and/or import.

Power control systems are used to control the output from a DER system due to an external condition. For example, the output from a DER unit may be limited so that it does not export energy back into the Area EPS system at the PCC. To accomplish this the power control system would sense the flow of energy at the PCC and relay that information back to the DER to limit DER output if there was any reverse energy flow at the PCC.

9.2. Power Control System Requirements

The power control system must be NRTL certified control system that meets the following requirements.

- Able to halt or reduce energy production within two seconds after either the period of continuous export to the Area EPS exceeds 30 seconds or the level of export exceeds the lessor of 100 kW or 10% of the DER nameplate rating.
- Able to monitor the total energy exported.
- Able to self-monitor the Power Control System, such that failure of the ability to monitor the energy flow or failure of the ability to control the output of the DER, results in halting the production of energy by the DER or the separation of the DER system from parallel operation with the Area EPS.
- The configuration and settings governing the power control limiting functions shall be password protected, accessible only by qualified personnel.
- The power to the control system must be battery backed up and if the power to the control is not available the DER system must be blocked from operation.

9.3. Documentation

DER applications that include a power control system must also include additional information specific to the power control system. At minimum, the following information should be supplied to the Area EPS Operator regarding the power control system.

- Make and model of the power control system.
- Electrical schematic of the monitoring for the power control system.
- User manual for the control of the power control system.
- Response time to modifying the output of the DER, in response to a large step change in the local electrical loads.
- Description of the operating reason and modes (shown in the user manual) which will be utilized.
- Description of how other operating modes (shown in the user manual) are being restricted so they are not able to be enabled.
- Other information which is useful to help the Area EPS Operator understand the power control system.

Prior to final interconnection, the Interconnection Customer shall supply updated power control system documentation to the Area EPS Operator.

9.4. Inadvertent Export

For installations with Power Control Systems inadvertent export is the flow of energy, in excess of a defined amount, through the PCC and back onto the Area EPS. Inadvertent export can have a detrimental effect on the Area EPS, damaging equipment or causing a power outage.

Inadvertent export shall be limited to 10% of the nameplate DER rating or 100 kW, whichever is less, for a maximum of 30 seconds. The cumulative amount of inadvertent exported energy from the Local EPS to the Area EPS, across the PCC, in any billing month shall be less than the on-site aggregated DER Nameplate Rating(s) multiplied by one hour. The power control system shall be designed to limit inadvertent export to these levels, unless mutually agreed to between the Interconnection Customer and Area EPS Operator and documented in the Operating and Maintenance Requirements section of the Interconnection Agreement.

Any amount of inadvertent export of real power across the PCC lasting longer than 30 seconds for any single event shall result in the disconnection of the DER system from the Area EPS within two seconds of exceeding the 30 second duration limit.

10. Interoperability

10.1. Overview

Depending on the method of interconnection and the size of the DER system, there are different interoperability requirements. Information from the DER is needed for the Area EPS Operator to perform fault analysis, load flow and system reliability analysis. Remote monitoring and remote control may be required depending on the size of the DER, type of interconnection and the mode of operation. In general, Table 7 displays the need for remote monitoring and remote control of the DER by size. DER with ESS that do not export may have different monitoring and control requirements. Specific remote monitoring and control requirements will be identified in the Operating and Maintenance Requirements of the Interconnection Agreement.

Table 11: Monitoring and Control Requirements for DER Systems

Monitoring and Control Requirements for DER Systems		
DER System Nameplate Capacity	**DER Remote Monitoring**	**DER Remote Control**
0 – 250 kW	None Required	None Required
250 kW – 1,000 kW	SCADA Monitoring possible, pending review by EPS	Remote control via Area EPS Operator's SCADA Possible, pending review by EPS
> 1,000 kW	SCADA Monitoring Required	Remote control via Area EPS Operator's SCADA Likely, pending review by EPS

10.2. Sales to Parties Other Than the Area EPS Operator

The TSM does not address the metering, monitoring and control requirements for DER system whose energy sales are to a party other than the Area EPS Operator. For energy sales to a party other than the Area EPS Operator, the monitoring and control requirement will be identified in the Operating and Maintenance Requirements section of the Interconnection Agreement.

10.3. Level of Communication Required

When SCADA monitoring or SCADA monitoring and control is required, the DER Owner is responsible for the cost to provide the communications to the Area EPS Operator's control center. For DER system larger than 1,000 kW requiring monitoring and control, the Area EPS Operator will install the communication channel. The Interconnection Customer is responsible for the Area EPS Operator's cost of the communication channel and associated hardware.

The communication channel shall meet the following requirements:

- Available via a VPN tunnel,
- Able to support a polling rate of once every 2 seconds.
- Encrypted,
- Utilize DNP3.0 protocol, and
- Include a battery backup system that can last for a minimum of 8 hours during an Area EPS outage.

10.4. Level of Monitoring and Control Required

The actual list of status, control and analog points required to be monitored and controlled by the Area EPS Operator are to be defined in the Operating and Maintenance Requirements section of the Interconnection Agreement.

In general, the minimum points that will be required for DER systems 1,000 kW and greater are:

- Status Points
  - Lockout relay status

- High voltage alarm
- Low voltage alarm
- Relay failure alarm (for each protective relay)
- Interconnection breaker(s) status (open/close)
- DC battery charger alarm (if applicable)
- General trouble alarms (temperature, access, etc.)
- Control Points
- Remote control of interconnection breaker(s) (if applicable)
- Ability to curtail the output of the DER to a specific level (may be required in the future)
- Ability to remotely change and/or monitor modes of operations that are active (may be required in the future)

- Analog Values
    - Phase voltage (phase to ground)
    - DER phase current (amp) output
    - Power Factor (including leading/lagging)
    - DC voltage of backup battery system
    - Three-phase real (kW) and reactive (kVA) power flow of each DER unit

Contact Area EPS Engineering Department to discuss wiring for minimum SCADA points. Other specific requirements will be included in the Interconnection Agreement.

10.5. Security

In general, all physical, network and local DER communication interface security protections should be identified by the Interconnection Customer and approved by the Area EPS Operator. Specific security requirements are listed in Sections 10.5.1, 10.5.2 and 10.5.3.

10.5.1. Physical and Front Panel

The Interconnection Customer shall maintain physical security for the DER equipment and all communication interfaces at the DER site. All configuration settings for the DER system shall be password protected to allow access only to qualified personnel. Other physical security protections shall be identified by the Interconnection Customer and approved by the Area EPS Operator.

10.5.2. Network Security

Dependent on the DER interconnection, additional network security may apply. If needed, the additional requirements will be identified in the Operating and Maintenance Requirements section of the Interconnection Agreement.

10.5.3. Local DER Communication Interface Security

Dependent on the DER interconnection, additional local DER communication interface security may apply. If needed, the additional requirements will be identified in the Operating and Maintenance Requirements section of the Interconnection Agreement.

11. Energy Storage Systems

11.1. Grid Support Functions

The TSM will not address technical issues that may arise with grid support functions. Grid support functions, such as frequency and voltage support, are currently not address by the Area EPS Operator’s rate tariff. Until MISO rules and required associated Minnesota PUC dockets have been determined, the use of an ESS to provide grid support functions is not allowed.

11.2. Common Modes of Operation

Energy storage systems are still an evolving technology with different use cases and modes of operation. Multiple control modes may be utilized by the Interconnection Customer. When applying for interconnection with the Area EPS, the DER Applicant should indicate what control modes of operation are being utilized. The Interconnection Customer must not change the control mode of the ESS without notification to the Area EPS Operator. The Area EPS Operator only studies the ESS under the indicated operation mode(s) listed on the original interconnection application. Common modes of operations used in ESS are explained in Appendix C.

11.3. Enter Service

After any sustained electrical outage, the ESS shall be configured to not immediately initiate recharging of the ESS. Per the IEEE 1547 standards the ESS shall wait a minimum of 5 minutes after the Area EPS is reenergized and provides a stable voltage, before initiating recharging of the ESS.

It is preferable to delay any recharging of the ESS for a minimum of 10 minutes after reenergization of the Area EPS, to allow the distribution system to fully stabilize and reduce the possibility of additional electrical demand caused by the recharging of the ESS to overload the distribution system.

To help reduce the possibility of step voltage issues and other distribution system issues, it is preferable to have the ESS control system ramp up the recharging level from 0-100% over a 5-minute time period upon entering service.

11.4. Modification of Control Modes

ESS Control Modes may not necessarily be considered a Material Modification, however the Interconnection Customer shall notify the Area EPS Operator of an unapproved ESS Control Mode prior to the change being implemented. The Area EPS Operator shall discuss with the Interconnection Customer the need, or lack thereof, to review the proposed ESS Control Mode for safety, power quality or reliability reasons.

The Interconnection Customer can inform the Area EPS Operator of a change in ESS control mode by emailing the Area EPS Operator's DER Coordinator a DER Alteration

Notification indicating the change in control mode. The DER Alteration Notification is shown in Appendix F. The DER Coordinator can be reached at DER@rpu.org. The ESS should not be operated in the new control mode without approval from the Area EPS Operator.

12. Metering Requirements

The metering requirement for each DER system will depend on the DER size, voltage, location, interconnection type and application rate schedules. It is the Interconnection Customer's responsibility to provide metering sockets and cabinets for instrument transformers as applicable. All existing and new meter sockets shall meet the current requirements of the Area EPS Operators current Electric Service Rules (www.RPU.org). The Area EPS Operator will provide the meter(s), CTs and VTs, unless the DER sales are to a third party. For DER with sales to a third party, the Interconnection Customer shall be responsible for all metering costs incurred by the Area EPS Operator.

12.1. DER Interconnection on Services with Subtractive Metering

Subtractive Metering is NOT ALLOWED by RPU.

12.2. Metering Required for DER Installation

The metering required for DER system depends on the size and type of DER, the method of interconnection and applicable rate programs the DER may take part in. There may be unique installations which may require deviations from requirements listed in this document. Deviations from this specification will be documented in the Operating and Maintenance Requirements section of the Interconnection Agreement.

The location and of all metering shall be subject to the requirements of applicable section of the Area EPS current Electric Service Rules and Regulations.

12.3. Main Service Meter

The main service meter, is located at the PCC, unless mutually agreed upon between the Area EPS Operator and Interconnection Customer, and is the meter the Area EPS Operator shall use for billings purposes. This is commonly called a bidirectional meter.

12.4. Production Meter

A production meter shall be required by the Area EPS Operator and is located electrically at the PoC. This meter will monitor the power flow to and from the DER. The production meter may be used for incentive programs or standby calculations and provides the Area EPS Operator with necessary information to properly engineer a safe and reliable grid. The Area EPS Operator does require a production meter.

12.5. Production Meter Requirement

12.5.1. DER Systems with ESS

There are multiple variations of DER systems that include ESS. Depending on the configuration, non-exporting DER systems that incorporate ESS may not need a production meter. Consult with the Area EPS Operator to determine the proper metering needs.

12.5.2. Extended Parallel DER Interconnections < 40 kW

For extended parallel DER interconnection that are sized less than 40 kW, the Area EPS Operator requires the main meter at the PCC, and a separate production meter at the PoC. The Area EPS Operator will reprogram or replace the main service meter to be able to measure and record power flow in both directions. It is the responsibility of the Interconnection Customer to install and provide the appropriate meter sockets and cabinets for instrument transformers.

12.5.3. Extended Parallel DER Interconnections 40 kW and Larger

The Area EPS Operator requires the main meter at the PCC and a production meter at the PoC. The Area EPS Operator will reprogram or replace the main service meter to be able to measure and record power flow in both directions. It is the responsibility of the Interconnection Customer to install and provide the appropriate meter sockets and cabinets for instrument transformers. The Area EPS Operator will provide the meter to record production. For DER systems where the PCC and PoC are the same location a single meter can perform both types of metering.

12.5.4. All Other DER Interconnections

1) Contact the Area EPS for other DER interconnections that are not extended parallel.
2) See Appendix D for expected metering configurations

12.6. Acceptable Metering

A brief list of metering specifications is listed in the following subsections. A complete list of details and applicable references to acceptable metering voltages, metering sockets and configurations are outlined in EPS Electric Rules and Regulations (available online). Deviations from the Area EPS requirements will need to be mutually agreed to in writing by the Area EPS Operator and documented in the Operating and Maintenance Requirements section of the Interconnection Agreement. The specifications for meter socket location and accessibility shall be maintained for the life of the meter use. If changes cause the meter to no longer meet the stated specifications, the meter shall be moved to a new mutually agreed accessible location at the expense of the Interconnection Customer.

12.6.1. Meter Sockets

The interconnection owner is responsible for purchasing and installing a meter socket that meets the following requirements and is appropriate for the service connect.

1) Meter sockets must be UL (Underwriters Laboratories) of ARL (Applied Research Laboratories) approved.
2) All metering for a single service must be grouped in a 10-foot area.

3) All self-contained meter sockets must be a ringless lever bypass type socket with a manually operated lever bypass.

4) Must meet the requirements of the Area EPS Electric Service Rules (www.RPU.org).

12.6.2. Location and Accessibility

The meter socket shall be installed in a location that meets the requirements outlined in the current version of the Area EPS published Electric Service Rules (www.rpu.org)

Meter Requirements Three Phase:

See Area EPS published Electric Service Rules (www.RPU.org) and seek direction from RPUs Engineering Department by sending a request for assistance to DER@rpu.org

If at the production meter location the voltage is over 240 volts or the generators output is over 320 amps then potential and current transformers shall be required for metering. Contact the Area EPS for assistance at DER@rpu.org.

13. Signage and Labeling

13.1. General Requirements

All signage and labeling shall meet applicable NEC requirements including NEC 110.21 (B) and 690.13.

13.2. Utility AC Disconnect

The Utility AC disconnect shall be labeled as “UTILITY AC DISCONNECT”. The Utility AC Disconnect shall be located within 10 feet of the main service meter in a locating meeting the requirements specified in the Area EPS Electric Service Rules (www.RPU.org). The Area EPS Operator and the Interconnection Customer may mutually agree to install the Utility AC Disconnect at a location greater than 10 feet from the main service meter.

13.2.1. Remotely Located Utility AC Disconnect

If the Utility AC Disconnect is not located within 10 feet of the main service meter, a permanently affixed waterproof and UV stabilized placard shall be located within 10 feet of the main service meter. The placard shall include a mapped representation of the property with the location of the Utility AC Disconnect clearly denoted. A copy of the proposed placard shall be submitted to the Area EPS Operator with the interconnection application.

13.2.2. Multiple AC Disconnects

If a single Utility AC Disconnect cannot be used to disconnect all DERs, all Utility AC disconnects should include numerical identification such as “UTILITY DER AC DISCONNECT 1 OF 2” or similar. The number of disconnects required to be operated to isolate the DER from the utility should be clear. A permanently affixed waterproof and UV stabilized placard shall be located within 10 feet of the main service meter clearly indicating the number and locations of the multiple Utility AC Disconnects. A copy of the proposed placard shall be submitted to the Area EPS Operator with the interconnection application.

13.3. Production Meter

The production meter shall be labeled as “DER PRODUCTION METER” or similar. If there are multiple DER types present at a location the production meter shall indicate the type of DER behind the meter.

14. Test and Verification Requirement

14.1. Applicability

Testing and verifications of the Interconnection Customer’s DER system to validate compliance with the interconnection agreement, TIIR and Area EPS Operator’s TSM is critical to maintaining the safe and reliable system. The testing and verifications requirements that follow will apply to the RPA and PCC unless mutually agreed upon between the Area EPS Operator and the Interconnection Customer.

14.2. Certified DER Systems

It is understood that DER systems that are certified by UL 1741 / IEEE 1547 have already undergone scrutiny and testing. As such the testing required to commissioning these systems is designed to recognize the previous testing and focus on integration with the Area EPS and the final installed DER. The following testing requirements shall be met prior to parallel operation with the Area EPS:

1) Verifications of certified equipment make and model.
2) Verification of system wiring.
3) For new installations, verification of meter with Area EPS Operators metering system.
4) Verification of anti-islanding.
5) Verification of grounding.

14.3. Non-Certified DER Systems

For non-certified systems it is the Interconnection Customer’s responsibility to provide a final design for approval and to install the protective measures required by the Area EPS Operator. Mutually agreed upon exception may at times be necessary and desirable. Prior to Commissioning of the DER the Interconnection customer shall provide the design with proof that it shall not connect or close into a de-energized Area EPS. The Interconnection Customer shall obtain written approval of the design as installed prior to completing the commissioning testing of the DER.

14.4. Pre-Energization Testing – Interconnection Customer

The following testing shall be performed by the Interconnection Customer. The Area EPS Operator has the right to witness all field test and review all records prior to allowing the system to be made ready for normal operation. The Area EPS Operator shall be notified with adequate lead time of witness testing in accordance to - M-MIP[2].

1) Grounding shall be verified to ensure that it complies with this specification, the NESC and the NEC.
2) CT's (Current Transformers) and VT's (Voltage Transformers) used for monitoring and protection, shall be tested to ensure correct polarity, ratio and wiring.
3) CT's shall be visually inspected to ensure that all grounding and shorting connections have been removed where required.
4) Breaker / Switch tests – Verify that the breaker or switch cannot be operated with interlocks in place or that the breaker or switch cannot be automatically operated when in manual mode. (The intent of this test is to ensure that the breaker or switch controls are operating properly).
5) Relay Tests – All protective relays shall be calibrated and tested to ensure the correct operation of the protective element. Documentation of all relay calibration tests and settings shall be furnished to the Area EPS Operator.
6) Trip checks – Protective relays shall be functionally tested to ensure the correct operation of the complete system. Functional testing requires that the complete system is operated by the injunction of currents and/or voltage to trigger the relay elements and prove that the relay element trips the required breaker, lockout or provides the correct signal to the next control element. Trip circuit shall be proven through the entire scheme (including breaker trip).
7) Remote Control, SCADA and Remote Monitoring tests – All remote-control functions and remote monitoring points shall be verified operational. For some monitoring points it may not be possible to verify analog values prior to energization. Where appropriate, those points may be verified during the energization process.
8) Phase Tests – the Interconnection Customer shall work with the Area EPS Operator to complete the phase test to ensure proper phase rotation of the DER system and wiring.
9) Synchronizing test – The following tests shall be done across an open switch or racked out breaker. The switch or breaker shall be in a position that it is incapable of closing between the Generation System and the Area EPS for this test. This test shall demonstrate that at the moment of the paralleling-device closure, the frequency, voltage and phase angle are within the required ranges, stated in IEEE 1547. This test shall also demonstrate that if any of the parameters are outside of the ranges stated; the paralleling device shall not close. For inverter-based interconnected systems this test may not be required unless the inverter creates fundamental voltages before the paralleling device is closed.

[2] *M-MIP Simplified Process section 8.3, Fast Track Process section 9.4 and Study Process section 11.3*

14.5. Energization Testing Criteria

Some tests are unable to be performed prior to interconnection with the Area EPS. Once the pre-energization tests are completed, the DER shall be integrated and the energization tests shall be performed. For larger and more complex DER systems the Interconnection Customer and Area EPS Operator should work together to develop the required testing procedure. Final proposed testing procedure shall be submitted to the Area EPS Operator prior to energization testing. The testing procedure should include the location, method of operation and verification for each step. At minimum, the testing procedure shall include the steps listed in Section 13.5.1 and 13.5.2.

14.5.1. Installation Verification

1) Prior to the anti-islanding testing, the DER system shall have the following verified:
2) That there is continuous, unescorted site access to the Area EPS equipment and Utility DER AC Disconnect is available. Site access means drivable and keyless access.
3) The DER installation matches the submitted one-line diagram that was approved by the Area EPS Operator.
4) There is proper labeling of disconnect switches, meters and placards, if necessary.
5) That the Interconnection Customer will verify the settings and firmware of the inverters, protective devices, power control systems and other hardware and software components comply with the TIIR, Area EPS Operator's TSM, operating agreements and match the previously approved settings.

14.5.2. Anti-Islanding Test

For DER systems that operate in parallel with the Area EPS, the anti-islanding test procedure shall, at minimum, contain the following steps:

1) The DER system shall be placed into normal operations.
2) The DER system shall be verified it is energized and generating.
3) The Area EPS source shall be removed from the DER system. For multi- phase systems. Each phase will be tested individually in addition to simultaneously.
4) The DER system shall be verified that it either separate from the Area EPS together with the local load or the DER system shall stop operating.
5) The DER system shall be reconnected to the Area EPS. The DER generation shall not parallel with the Area EPS for a period less than 5 minutes.

For each step, the testing procedure shall identify which device shall be operated to complete the step. In verification step, the testing procedure shall identify the point of measurement.

14.5.3. Additional Onsite Testing

Depending on the complexity of the DER system, additional energization tests may be required. Examples of additional tests include phase testing, control mode verification, SCADA and communication verification. These additional tests shall be listed in the Interconnection Customer's submitted testing procedure as applicable.

14.6. Periodic Testing and Documentation

All interconnection-related protection systems shall be periodically tested and maintained, by the Interconnection Customer, at intervals specified by the manufacturer or system integrator. These intervals shall not exceed five years. Periodic test reports and a log of inspections shall be maintained, by the Interconnection Customer and made available to the Area EPS Operator upon request. The Area EPS Operator shall be notified prior to the periodic testing of the protective systems, so that Area EPS personnel may witness the testing, if so desired.

14.6.1. Battery Documentation

Any system that depends upon a battery for trip/protection power shall be checked and logged once per month for proper voltage. Once every four years the battery(s) must be either replaced or a discharge test performed. Longer intervals are possible using the "station class batteries" and Area EPS Operator approval.

14.7. Failure Protocol

If the DER fails testing or verification, the Interconnection Customer shall address outstanding issues and provide updated documentation to the Area EPS Operator regarding the corrections made. The Interconnection Customer shall re-schedule the onsite testing with the Area EPS Operator and provide a revised testing procedure, if necessary.

14.8. Modification to Existing DER

Any time the interface hardware or software, including protective relaying and generation control systems are replaced and/or modified, the Area EPS Operator shall be notified. This notification shall, if possible, be with adequate notice so the Area EPS personnel can be involved in the planning for the modification and/or witness the verification testing. Verification testing shall be completed on the replaced and/or modified equipment and systems. The involvement of the Area EPS personnel will depend upon the complexity of the DER system and the component being replaced and/or modified.

15. Sample Documents for Simplified Process

15.1. Introduction

Interconnection customer shall maintain a system one-line diagram, site diagram and testing procedure with latest results.

- All documentation shall include the following:

- Interconnection Customer's Name
- Interconnection Agent's Name, Address, and Phone Number
- Date and revision

15.2. One-Line Diagram

The one-line diagram shall include, but not limited to, the following information:

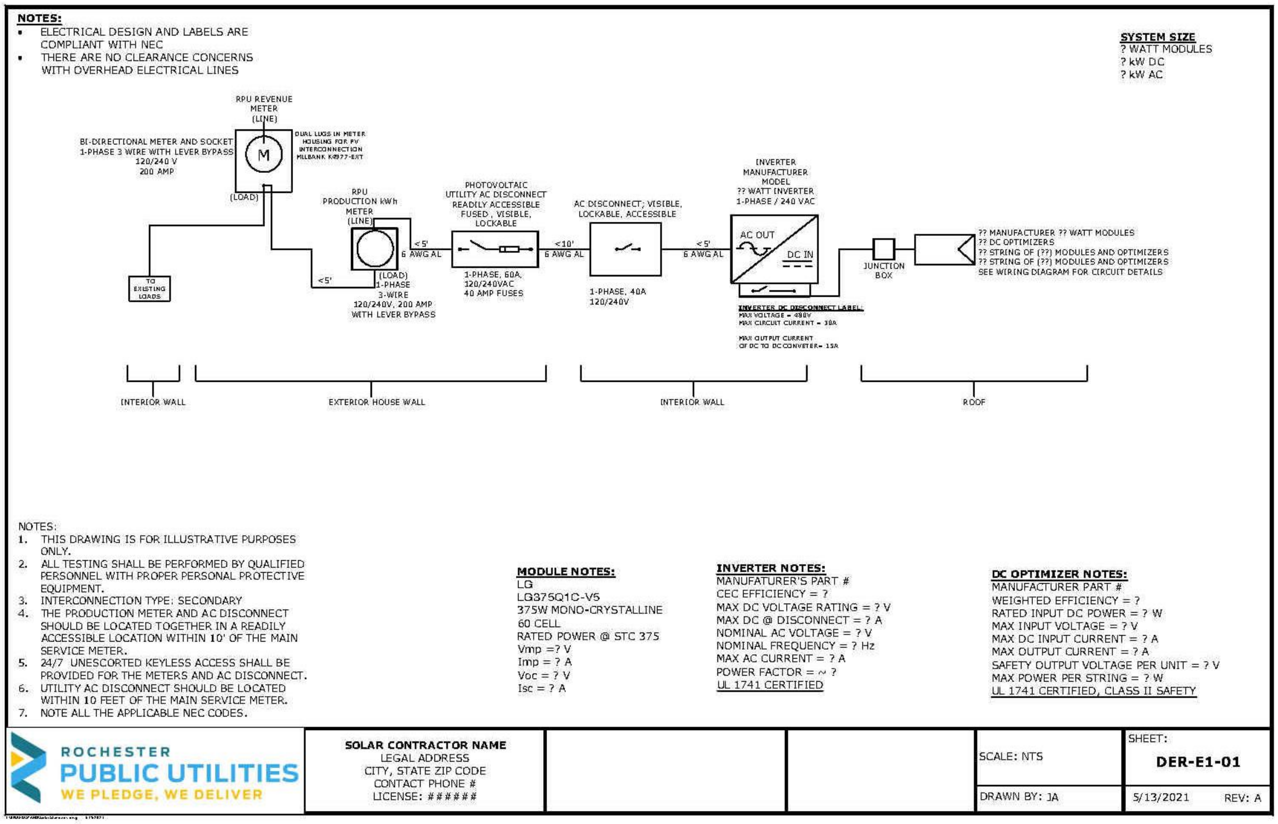
- Applicant Name
- Installer name and contact information
- Address where DER system will be installed
- Correct electrical position of all equipment, including but not limited to: Panels, Inverter, DC and AC disconnects, and metering equipment.
- Indicate the line and load side of the production and revenue meters.
- Distance between equipment
- Labeling found on equipment (actual labeling is typically on a separate drawing that shall be included with the application)
- Total Aggregated AC nameplate rating of DER
- DER protection elements

The one-line diagram shall be signed and stamped by a Minnesota Professional Engineer if the DER is larger than 20 kW and uncertified or larger than 250 kW and certified.

Key labels:

Utility AC Disconnect, DER Production Meter, Revenue Meter, Load and Line side of meter sockets, System AC and DC Rating, Customer Name and Address

Figure 14.1 Example Simplified One-Line Diagram



15.3. Site Diagram

Site Diagram shall include the following:

- Customers signature if an Application Agent is being used
- Shall be to scale
- Location of DER
- Location of meter(s)
- Location of Utility AC disconnect
- Location of PCC/RPA/PoC
- If DER installed on a different structure than the revenue meter:
    - If underground, shall include any easements/right of ways

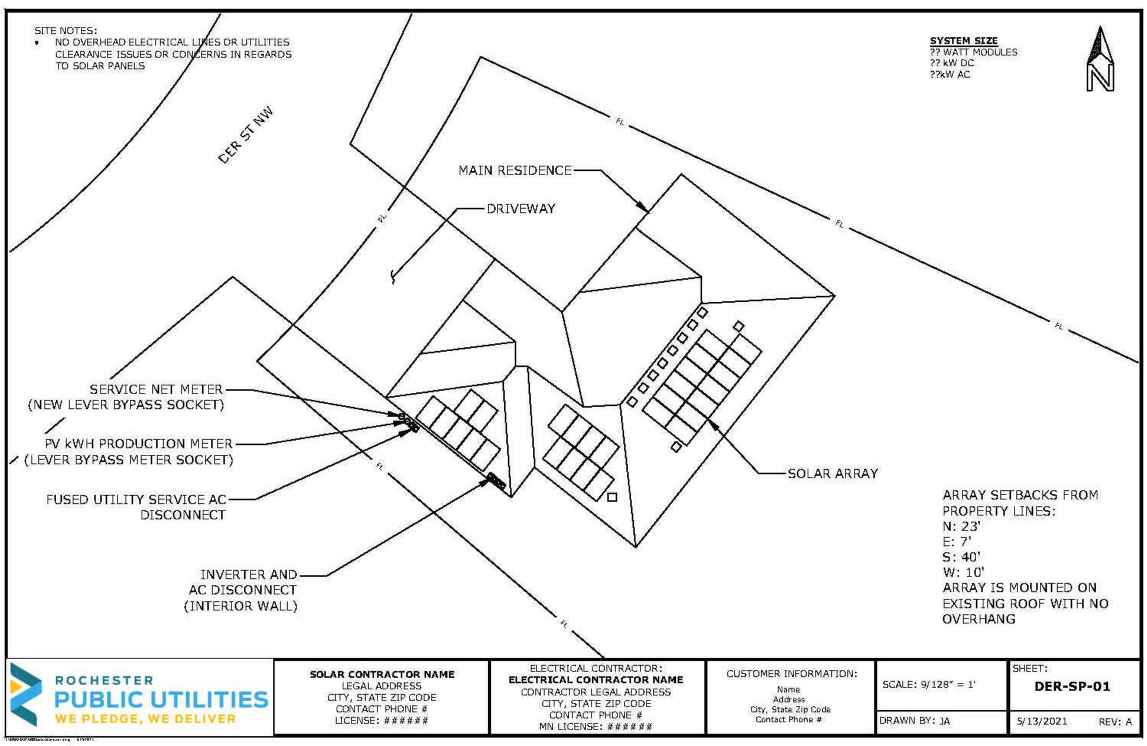


Figure 14.2 – Sample Simplified Site Diagram

15.4. Testing Procedure

General Process for Simplified Testing Procedures

- Verify installation matches design evaluation
    - Verify inverter model matches application
    - Verify certified inverter

- Verify electrical inspection sticker
- Verify correct labeling / signage
- Verify Utility DER AC Disconnect Switch is lockable and has visual open
- Verify DER system installation matches application one-line
- Verification of operational and protection settings
- Verify metering and Utility DER AC Disconnect Switch are accessible by Area EPS Operator

- Field Testing
    - On-off test
    - Open phase testing (if applicable for multiphase systems)

An example of a Simplified DER testing procedure is found in Appendix E.

Appendix A – Types of Interconnection

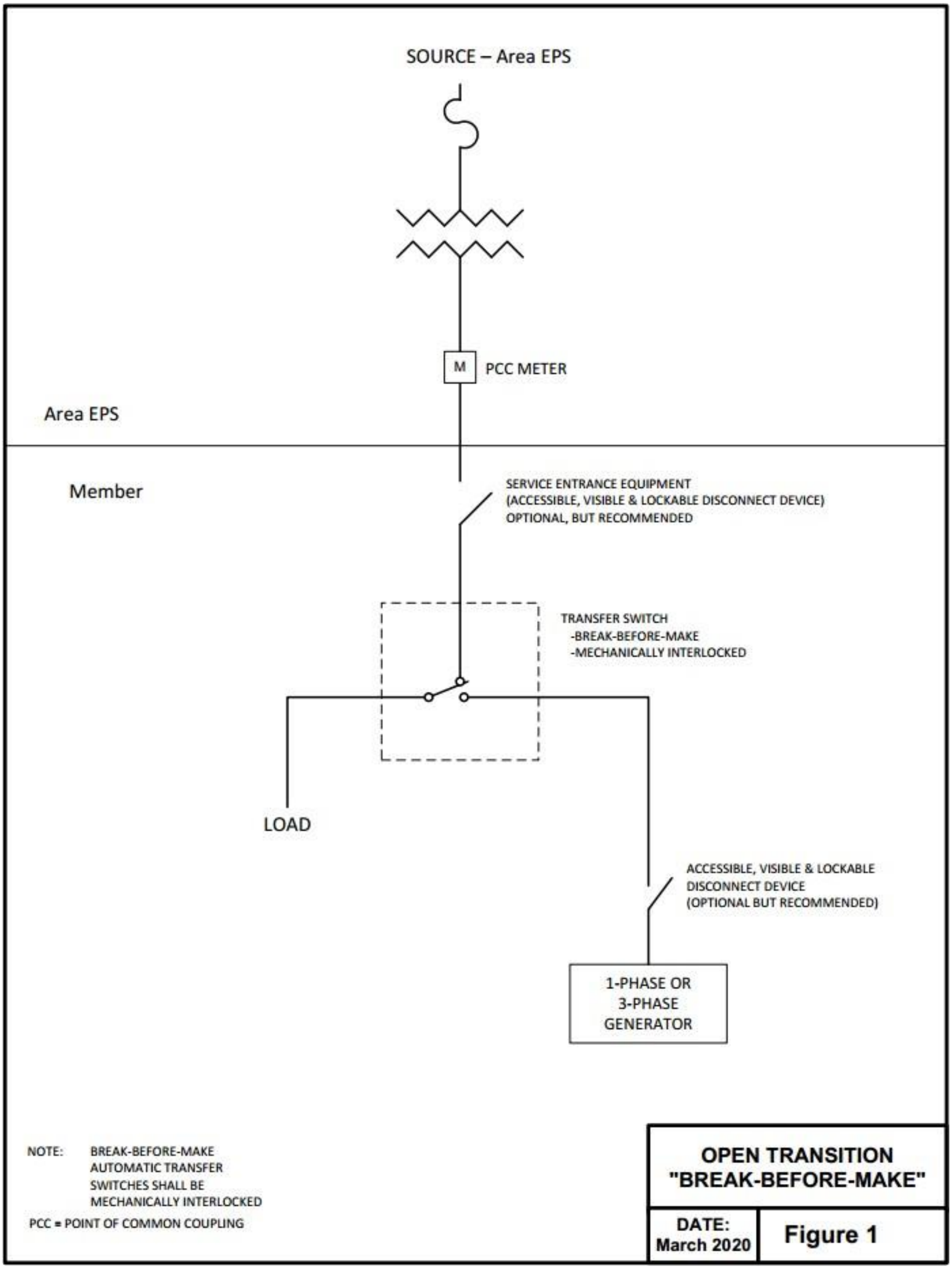
The way the DER system is connected to and disconnected from the Area EPS can vary. Most transfer systems normally operate using one of the following five methods of transferring the load from the Area EPS to the DER system.

If a transfer system is installed which has a user accessible selection of several transfer modes, the transfer mode that has the greatest protection requirements will establish the protection requirements for that transfer system.

Open Transition (Break-Before-Make) Transfer Switch

With this transfer switch, the load to be supplied from the DER is first disconnected from the Area EPS and then connected to the DER. This transfer can be relatively quick, but voltage and frequency excursions are to be expected during transfer. Computer equipment and other sensitive equipment will shut down and reset. The transfer switch typically consists of a standard UL approved transfer switch with mechanical interlocks between the two source contactors that drop the Area EPS source before the DER is connected to supply the load.

1) To qualify as an Open Transition switch and the limited protective requirements, mechanical interlocks are required between the two source contacts. This is required to ensure that one of the contacts is always open and the generating DER is never operated in parallel with the Area EPS. If the mechanical interlock is not present, the protection requirements are as if the switch is a closed transition switch.
2) As a practical point of application, this type of transfer switch is typically used for loads less than 500 kW. This is due to possible voltage flicker problems created on the Area EPS, when the load is removed from or returned to the Area EPS source. Depending upon the Area EPS's stiffness, this level may be larger or smaller than the 500-kW level.
3) Figure 1 on the following page provides a typical one-line of this type of installation.


SOURCE – Area EPS
M
PCC METER
Area EPS
Member
SERVICE ENTRANCE EQUIPMENT
(ACCESSIBLE, VISIBLE & LOCKABLE DISCONNECT DEVICE)
OPTIONAL, BUT RECOMMENDED
TRANSFER SWITCH
-BREAK-BEFORE-MAKE
-MECHANICALLY INTERLOCKED
LOAD
ACCESSIBLE, VISIBLE & LOCKABLE
DISCONNECT DEVICE
(OPTIONAL BUT RECOMMENDED)
1-PHASE OR
3-PHASE
GENERATOR
NOTE: BREAK-BEFORE-MAKE AUTOMATIC TRANSFER SWITCHES SHALL BE MECHANICALLY INTERLOCKED
PCC = POINT OF COMMON COUPLING
OPEN TRANSITION
"BREAK-BEFORE-MAKE"
DATE:
March 2020
Figure 1

Quick Open Transition (Break-Before-Make) Transfer Switch

For a Quick Open Transition, the load to be supplied from the DER is first disconnected from the Area EPS and then connected to the DER, similar to the open transition. However, this transition is typically much faster (under 500 ms) than the conventional open transition transfer operation. Voltage and frequency excursions will still occur, but some computer equipment and other sensitive equipment will typically not be affected with a properly designed system. The transfer switch consists of a standard UL approved transfer switch, with mechanical interlocks between the two source contacts that drop the Area EPS source before the DER is connected to supply the load.

1) Mechanical interlocks are required between the two source contacts to ensure that one of the contacts is always open. If the mechanical interlock is not present, the protection requirements are as if the switch is a closed transition switch.

2) As a practical point of application this type of transfer switch is typically used for loads less than 500 kW. This is due to possible voltage flicker problems created on the Area EPS, when the load is removed from or returned to the Area EPS source. Depending upon the Area EPS's stiffness this level may be larger or smaller than the 500-kW level.

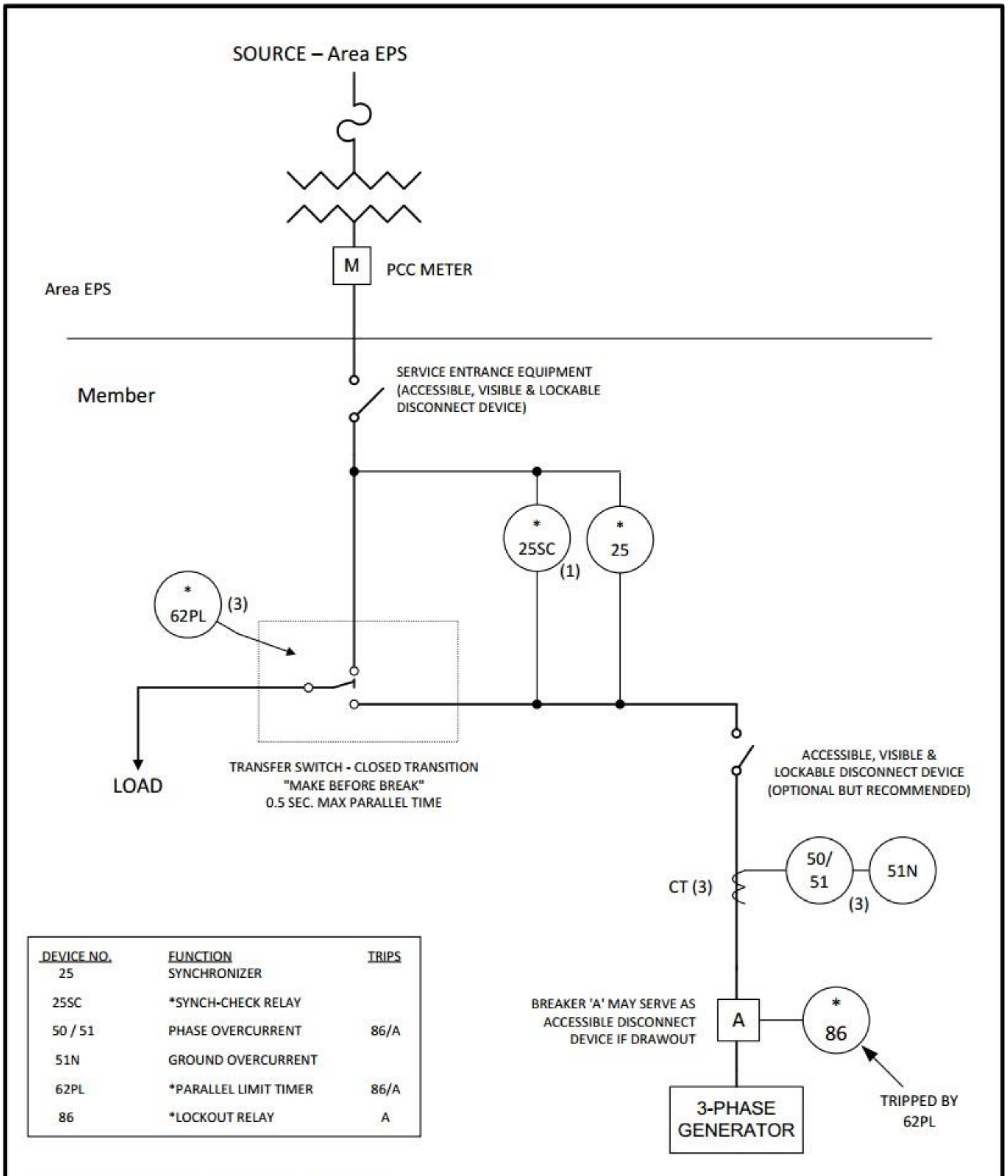
3) Figure 1 on the previous page provides a typical one-line of this type of installation and shows the required protective elements.

Closed Transition (Make-Before-Break) Transfer Switch

For Closed Transition, the DER is synchronized with the Area EPS prior to the transfer occurring. The transfer switch then parallels with the Area EPS for a short time (500 ms or less) and then the DER and load is disconnected from the Area EPS. This transfer is less disruptive than the Quick Open Transition because it allows the DER a brief time to pick up the load before the support of the Area EPS is lost. With this type of transfer, the load is always being supplied by the Area EPS or the DER.

1) As a practical point of application this type of transfer switch is typically used for loads less than 500 kW. This is due to possible voltage flicker problems created on the Area EPS, when the load is removed from or returned to the Area EPS source. Depending upon the Area EPS's stiffness this level may be larger or smaller than the 500-kW level.

2) Figure 2 on the following page provides a typical one-line of this type of installation and shows the required protective elements. The closed transition switch must include a separate parallel time limit relay, which is not part of the generation control PLC and trips the generation from the system for a failure of the transfer switch and/or the transfer switch controls.



DEVICE NO.	FUNCTION	TRIPS
25	SYNCHRONIZER	
25SC	*SYNCH-CHECK RELAY	
50 / 51	PHASE OVERCURRENT	86/A
51N	GROUND OVERCURRENT	
62PL	*PARALLEL LIMIT TIMER	86/A
86	*LOCKOUT RELAY	A

(1) (2) (3) INDICATES NUMBER OF PHASES TO BE MONITORED

* INDICATES MINIMUM REQUIRED PROTECTION
OTHER RELAYS SHOWN ARE RECOMMENDED FOR GENERATOR PROTECTION.

PCC = POINT OF COMMON COUPLING

CLOSED TRANSITION
"MAKE-BEFORE-BREAK"

DATE: March 2020	Figure 2

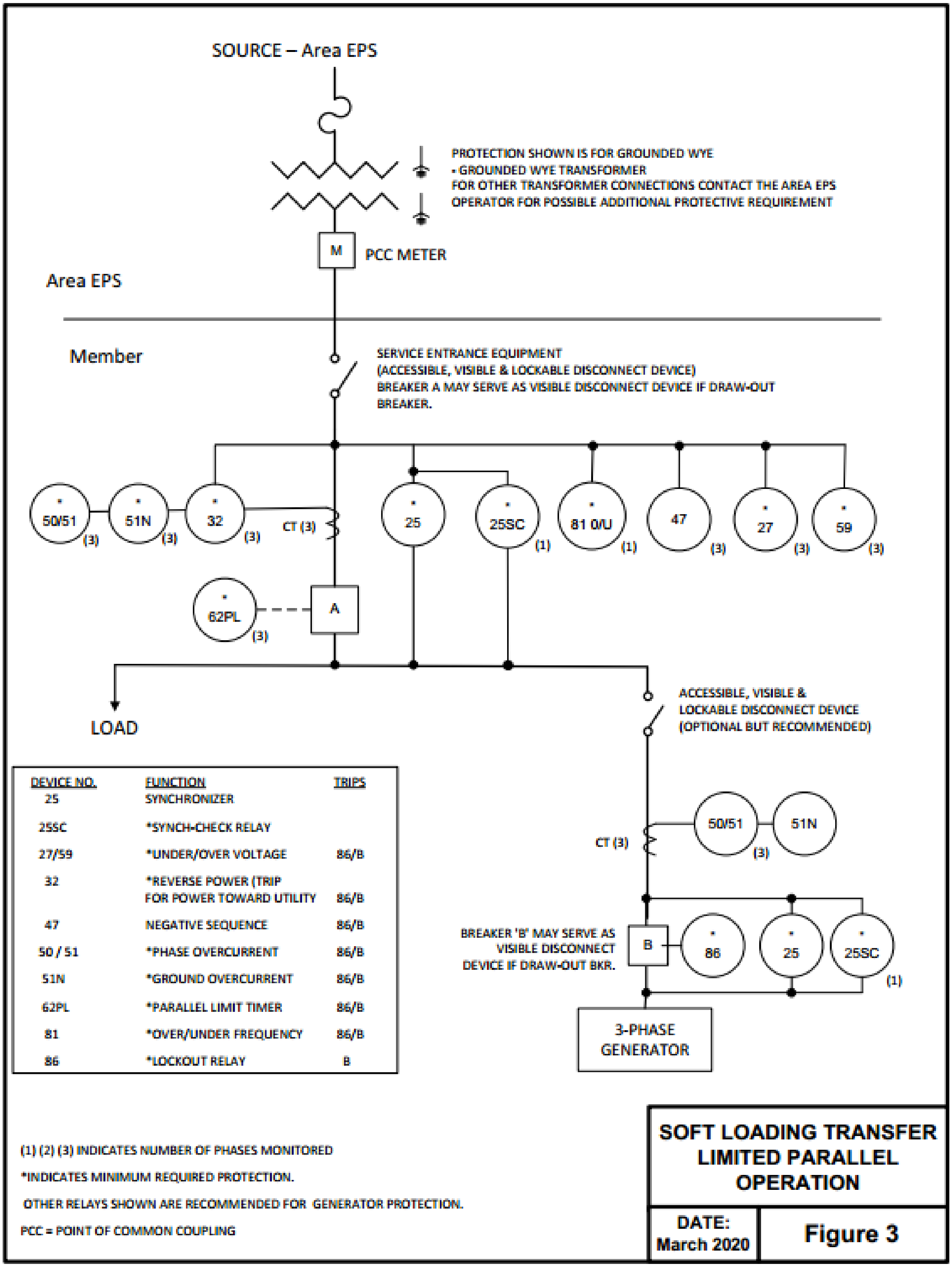
Soft Loading Transfer Switch – With Limited Parallel Operation

For this type of interconnection, the DER is paralleled with the Area EPS for a limited amount of time (generally less than 1-2 minutes) to gradually transfer the load from the Area EPS to the generating DER system. This minimizes the voltage and frequency problems, by softly loading and unloading the DER.

1) The maximum parallel operation shall be controlled, via a parallel timing limit relay (62PL). This parallel time limit relay shall be a separate relay and not part of the generation control PLC.

2) Protective Relaying is required as described in Section 6 of this document.

3) Figure 3 on the following page provides typical one-line diagrams of this type of installation and show the required protective elements.



DEVICE NO.	FUNCTION	TRIPS
25	SYNCHRONIZER	
25SC	*SYNCH-CHECK RELAY	
27/59	*UNDER/OVER VOLTAGE	86/B
32	*REVERSE POWER (TRIP FOR POWER TOWARD UTILITY	86/B
47	NEGATIVE SEQUENCE	86/B
50 / 51	*PHASE OVERCURRENT	86/B
51N	*GROUND OVERCURRENT	86/B
62PL	*PARALLEL LIMIT TIMER	86/B
81	*OVER/UNDER FREQUENCY	86/B
86	*LOCKOUT RELAY	B

(1) (2) (3) INDICATES NUMBER OF PHASES MONITORED

*INDICATES MINIMUM REQUIRED PROTECTION.

OTHER RELAYS SHOWN ARE RECOMMENDED FOR GENERATOR PROTECTION.

PCC = POINT OF COMMON COUPLING

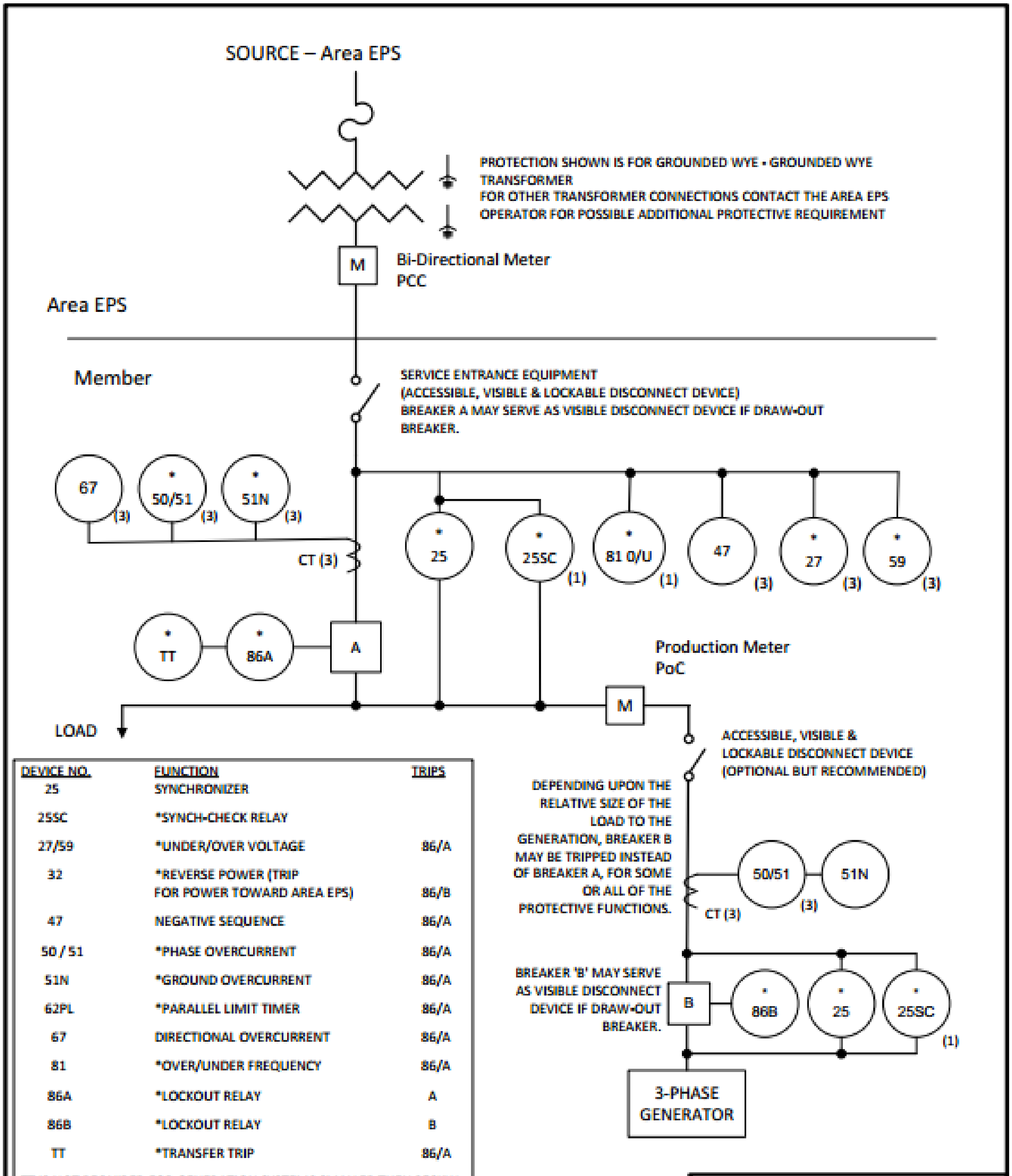
SOFT LOADING TRANSFER LIMITED PARALLEL OPERATION

DATE: March 2020	Figure 3

Soft Loading Transfer Switch – With Extended Parallel Operation

The DER is paralleled with the Area EPS in continuous operation. Special design, coordination and agreements are required before any extended parallel operation will be permitted. The Area EPS interconnection study will identify the issues involved.

1) Any anticipated use in the extended parallel mode requires special agreements and special protection coordination.
2) Protective Relaying is required as described in Section 6 of this document.
3) Figure 4 on the following page provides a typical one-line for this type of interconnection. It must be emphasized that this is a typical installation only and final installations may vary from the examples shown due to transformer connections, breaker configuration, etc.



DEVICE NO.	FUNCTION	TRIPS
25	SYNCHRONIZER	
25SC	*SYNCH-CHECK RELAY	
27/59	*UNDER/OVER VOLTAGE	86/A
32	*REVERSE POWER (TRIP FOR POWER TOWARD AREA EPS)	86/B
47	NEGATIVE SEQUENCE	86/A
50 / 51	*PHASE OVERCURRENT	86/A
51N	*GROUND OVERCURRENT	86/A
62PL	*PARALLEL LIMIT TIMER	86/A
67	DIRECTIONAL OVERCURRENT	86/A
81	*OVER/UNDER FREQUENCY	86/A
86A	*LOCKOUT RELAY	A
86B	*LOCKOUT RELAY	B
TT	*TRANSFER TRIP	86/A

TT IS NOT REQUIRED FOR GENERATION SYSTEMS SMALLER THEN 250KW

(1) (2) (3) INDICATES NUMBER OF PHASES MONITORED

*INDICATES MINIMUM REQUIRED PROTECTION.

OTHER RELAYS SHOWN ARE RECOMMENDED FOR GENERATOR PROTECTION.

PCC = POINT OF COMMON COUPLING

SOFT LOADING EXTENDED PARALLEL OPERATION

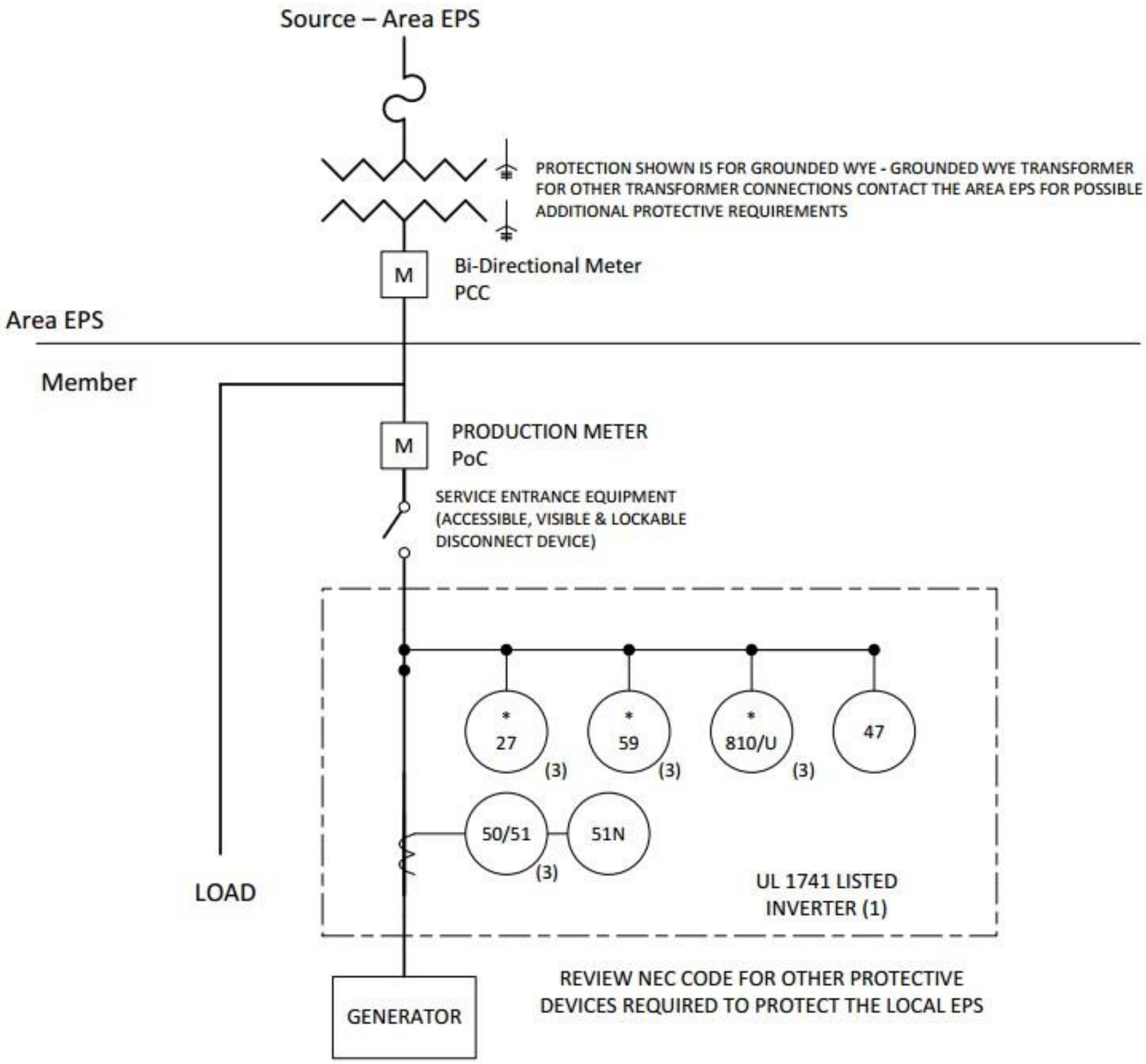
DATE: March 2020

Figure 4

Inverter Connection

An inverter Connection is a continuous parallel connection between the DER and Area EPS. Small generating DER systems may utilize inverters to interface to the Area EPS. Solar, wind and fuel cells are some examples of DER which typically use inverters to connect to the Area EPS. The design of such inverters shall either contain all necessary protection to prevent unintentional islanding, or the Interconnection Customer shall install conventional protection to affect the same protection. All required protective elements for a soft-loading transfer switch apply to an inverter connection. Figure 5 on the following page shows a typical inverter interconnection.

1) Inverter Certification – Prior to installation, the inverter shall be Type-Certified for interconnection to the electrical power system. The certification will confirm its anti-islanding protection and power quality related levels at the Point of Common Coupling. Also, utility compatibility, electric shock hazard and fire safety are approved through UL listing of the model. Once this Type Certification is completed for that specific model, additional design review of the inverter should not be necessary by the Area EPS Operator.
2) For three-phase operation, the inverter control must also be able to detect and separate for the loss of one phase. Larger inverters will still require custom protection settings, which must be calculated and designed to be compatible with the specific Area EPS being interconnected with.
3) A visible disconnect is required for safely isolating the DER when connecting with an inverter. The inverter shall not be used as a safety isolation device.
4) When banks of inverter systems are installed at one location, a design review by the Area EPS Operator must be performed to determine any additional protection systems, metering or other needs. The issues will be identified by the Area EPS Operator during the interconnection process.



NOTE (1): GRID SUPPORTING or SMART Inverters meeting UL-1741 SA requirements are preferred.

DEVICE NO.	FUNCTION
27/59	*UNDER/OVER VOLTAGE
47	NEGATIVE SEQUENCE
50 / 51	PHASE OVERCURRENT
51N	GROUND OVERCURRENT
81O/U	*OVER/UNDER FREQUENCY

(1) (2) (3) INDICATES NUMBER OF PHASES MONITORED

*INDICATES MINIMUM REQUIRED PROTECTION.

OTHER RELAYS SHOWN ARE RECOMMENDED FOR GENERATION PROTECTION

PCC = POINT OF COMMON COUPLING

ECP = DER ELECTRICAL CONNECTION POINT

INVERTER CONNECTED

DATE: March 2020

Figure 5

Appendix B – Relay Functions

Non-Certified installation, depending on the interconnection configuration, are required to provide the appropriate relay function listed in this section. The interconnection types in Appendix A will specify which relay function may be applicable.

Over-current relay (IEEE Device 50/51 or 50/51V) shall operate to trip the protecting breaker at a level to ensure protection of the equipment and at a speed to allow proper coordination with other protective devices. For example, the over-current relay monitoring the interconnection breaker shall operate fast enough for a fault on the customer's equipment, so that no protective devices will operate on the Area EPS. 51V is a voltage restrained or controlled over- current relay and may be required to provide proper coordination with the Area EPS.

Directional Over-Current Relay (IEEE Device 67) This element uses the phase relationship of the voltage and current to determine direction of the fault.

Over-Voltage Relay (IEEE Device 59) shall operate to trip the DER per the requirements of IEEE 1547. See table in Section 5.1.

Under-Voltage Relay (IEEE Device 27) shall operate to trip the DER per the requirements of IEEE 1547. See table in Section 5.1.

Over-Frequency Relay (IEEE Device 81O) shall operate to trip the DER off-line per the requirements of IEEE 1547. See table in Section 5.2.

Under-Frequency Relay (IEEE Device 81U) shall operate to trip the DER off-line per the requirements of IEEE 1547. See table in Section 5.2.

Synch Check Relay (IEEE Device 25 / 25SC) The Area EPS will provide the reference frequency of 60 Hz. The DER control system must be used to match this reference. The protective relaying in the interconnection system will be expected to maintain the frequency of the output of the DER.

Phase Sequence or Phase Balance Detection (IEEE Device 47) Provides protection for rotating equipment from the damaging effects of excessive negative sequence voltage resulting from a phase failure, phase unbalance and reversed phase sequence. This element helps the DER sense loss of source issues on the Area EPS.

Reverse Power Relays (IEEE Device 32) (power flowing from the DER to the Area EPS) shall operate to trip the DER off-line for a power flow to the system with a maximum time delay of2.0 seconds.

Lockout Relay (IEEE Device 86) is a mechanically locking device which is wired into the close circuit of a breaker or switch and when tripped will prevent any close signal from closing that device. This relay requires that a person manually resets the lockout relay before that device can be reclosed. These relays are used to ensure that a de-energized system is not reenergized by automatic control action and prevents a failed control from auto-reclosing an open breaker or switch.

Transfer Trip – All DERs are required to disconnect from the Area EPS when the Area EPS is disconnected from its source, to avoid unintentional islanding. A transfer trip system may be required to sense the loss of the Area EPS source for larger DERs which remain in parallel with the Area EPS. When the Area EPS source is lost, a signal is sent to the DER to separate the DER from the Area EPS. The size and type of the DER and the capacity and minimum loading on the Area EPS circuit will dictate the need for transfer trip installation. The Area EPS interconnection process will identify the specific requirements for the proposed DER system.

If multiple Area EPS sources are available, or multiple points of sectionalizing exist on the Area EPS, more than one transfer trip system may be required. The Area EPS interconnection process will identify the specific requirements for the proposed DER system in this situation. For some installations, the alternate Area EPS source(s) may not be utilized except in rare occasions. In this situation, the Interconnection Customer may elect to have the DER locked out when the alternate source(s) are utilized, if agreeable to the Area EPS Operator.

Parallel Limit Timing Relay (IEEE Device 62PL) set at a maximum of 120 seconds for soft transfer installations and set no longer than 500 ms for closed transfer installations, shall trip the DER circuit breaker on limited parallel interconnection systems. Power for the 62 PL relay must be independent of the transfer switch control power.

Minimum Input Relay (IEEE Device 37) is a setting within a digital relay that will trip the DER if the level of energy flow from the Area EPS goes below a set value. This protection system may be used by the DER to detect faults on the Area EPS. Minimum input relaying schemes must be set to trip immediately upon sensing under power levels and must coordinate with the Area EPS. Minimum input relaying is not allowed for DER systems which have the potential for inadvertent energy flow onto the Area EPS.

The Area EPS primarily uses SEL protective relays for distribution system protection. If DER protection devices are required to interface with RPU's SEL protective relays, SEL's Mirrored Bits communications protocol should be the communication scheme.

Table 7 – Summary of Relaying Requirements

Summary of Relaying Requirements								
Type of Interconnection	Over Current (50/51)	Voltage (27/59)	Frequency (81 O/U)	Reverse Power (32)	Lockout (86)	Parallel Limit Timer (62)	Synch Check (25)	Transfer Trip
Certified Inverter Connected < 250 kW	(1)	(1)	(1)	--	--	--	(1)	--
Certified Inverter Connected > 250 kW	Yes (2)	Yes (2)	Yes (2)	Yes (2)	Yes (2)	Yes (2)	Yes (2)	Yes (3)
Limited Parallel Quick Open Transition Mechanically Interlocked	--	--	--	--	Yes	Yes	Yes	--
Limited Parallel Closed Transition	--	--	--	--	Yes	Yes	Yes	--
Soft Loading Limited Parallel Operations	Yes	Yes	Yes	Yes	Yes	Yes	Yes	--
Soft Loaded Extended Parallel < 250 kW	Yes	Yes	Yes	--	Yes	--	Yes	--
Soft Loaded Extended Parallel > 250 kW	Yes	Yes	Yes	--	Yes	--	Yes	Yes (3)
Extended Parallel > 250 kW	Yes	Yes	Yes	Yes	Yes	--	Yes	Yes (3)

Note (1): Function is part of a certified inverter.

Note (2): For inverter-based DER that is 250 kW or larger, a breaker and relaying is required for interconnection with the Area EPS.

Note (3): Direct Transfer-Trip is required if the Area EPS determines the proposed DER cannot detect and trip for an Area EPS fault or loss of source supply to the Area EPS within an acceptable time-frame.

Appendix C – Types of ESS Control Modes

Common types of ESS control modes are listed in this section. Not all possible control modes are identified and many ESS vendors have different names for similar control modes. For clarity between the Area EPS Operator and the Interconnection Customer, it is helpful to identify which control modes the ESS is capable of and is using on the Storage Application using one of the control modes terms below.

Emergency Power

The emergency power control mode has the ESS only providing energy to the Local EPS during a power outage and not providing energy to the Local EPS in any other situation. This control mode would have the ESS remaining in a charged state until Area EPS was de-energized. Once the Area EPS was not the source of the local EPS, a switch opens isolating the backed-up load from of the Area EPS and the ESS would release energy. Upon reenergization of the Area EPS the switch closes the load so it is sourced from the Area EPS. The ESS would cease in all operation for ten minutes prior to moving to a state of charging. (See Section 10.3 Enter Service).

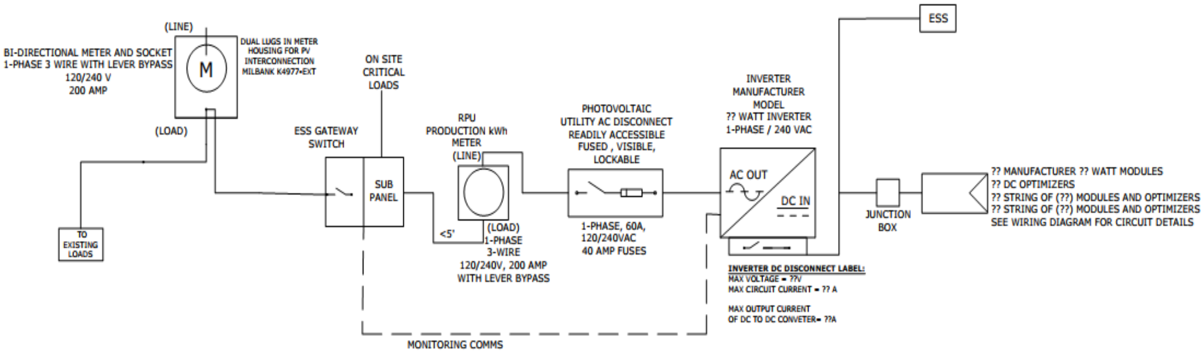
Figure 6. Example of Typical One-line Diagram for Emergency Power Control Mode

NOTES:

- ELECTRICAL DESIGN AND LABELS ARE COMPLIANT WITH NEC
- THERE ARE NO CLEARANCE CONCERNS WITH OVERHEAD ELECTRICAL LINES

ELECTRIC ONE-LINE DIAGRAM EMERGENCY POWER

SYSTEM SIZE
? WATT MODULES
? kW DC
? kW AC



NOTES:

1. THIS DRAWING IS FOR ILLUSTRATIVE PURPOSES ONLY.
2. ALL TESTING SHALL BE PERFORMED BY QUALIFIED PERSONNEL WITH PROPER PERSONAL PROTECTIVE EQUIPMENT.
3. INTERCONNECTION TYPE: SECONDARY
4. THE PRODUCTION METER AND AC DISCONNECT SHOULD BE LOCATED TOGETHER IN A READILY ACCESSIBLE LOCATION WITHIN 10' OF THE MAIN SERVICE METER.
5. 24/7 UNESCORTED KEYLESS ACCESS SHALL BE PROVIDED FOR THE METERS AND AC DISCONNECT.
6. UTILITY AC DISCONNECT SHOULD BE LOCATED WITHIN 10 FEET OF THE MAIN SERVICE METER.
7. NOTE ALL THE APPLICABLE NEC CODES.

MODULE NOTES:
LG
LG375Q1C-V5
375W MONO-CRYSTALLINE
60 CELL
RATED POWER @ STC 375
Vmp =? V
Imp = ? A
Voc = ? V
Isc = ? A

INVERTER NOTES:
MANUFATURER'S PART #
CEC EFFICIENCY = ?
MAX DC VOLTAGE RATING = ? V
MAX DC @ DISCONNECT = ? A
NOMINAL AC VOLTAGE = ? V
NOMINAL FREQUENCY = ? Hz
MAX AC CURRENT = ? A
POWER FACTOR = ~ ?
UL 1741 CERTIFIED

DC OPTIMIZER NOTES:
MANUFACTURER PART #
WEIGHTED EFFICIENCY = ?
RATED INPUT DC POWER = ? W
MAX INPUT VOLTAGE = ? V
MAX DC INPUT CURRENT = ? A
MAX OUTPUT CURRENT = ? A
SAFETY OUTPUT VOLTAGE PER UNIT = ? V
MAX POWER PER STRING = ? W
UL 1741 CERTIFIED, CLASS II SAFETY

ROCHESTER PUBLIC UTILITIES WE PLEDGE, WE DELIVER	**SOLAR CONTRACTOR NAME** LEGAL ADDRESS CITY, STATE ZIP CODE CONTACT PHONE # LICENSE: ######			SCALE: NTS	SHEET: **DER-E1-04**
				DRAWN BY: JA	5/18/2021 REV: A

Demand Reduction Management

The demand reduction management operating mode has the ESS releasing stored power to reduce the peak demand of the Local EPS. This control mode would have the ESS providing energy to the Local EPS while the Local EPS is also receiving energy from the Area EPS. The ESS would incorporate an energy management system that monitors the load of the Local EPS. When the Local EPS reaches a set demand point, the ESS would release stored power in specified amount. The result is the demand required from the Area EPS would stay at a levelized amount. This type of control mode can be used with electrical services that are billed retail with a volumetric energy component and a demand component. The example one-line of this type of control mode is shown in Figure 7.

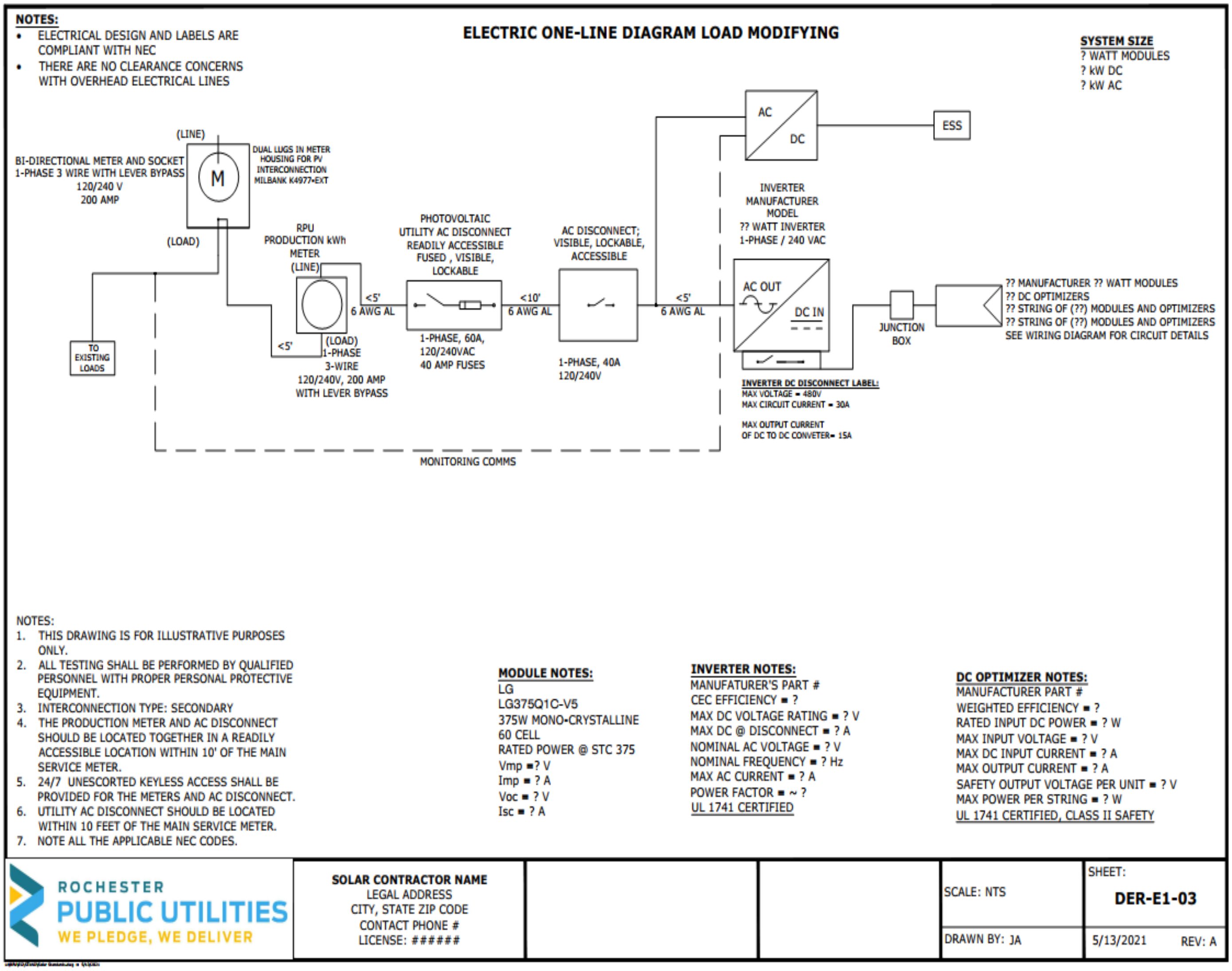
Non-Exporting, Self-Consumption

The non-exporting or self-consumption mode incorporates a generating DER, such as a solar system, that would charge the ESS. As the generation exceeds the load, the ESS is charged. When the load exceeds the generation, the ESS can release energy to maintain the power needs of the load is covered, but neither the ESS nor the generating DER (solar) will send power to the Area EPS. This control mode normally includes information from an energy management system. The example one-line of this type of control mode is shown in Figure 7.

Time-Of-Use Management

The time-of-use management control mode has the ESS charging when retail energy prices are low and releasing energy when energy prices are high, offsetting the need for the load to use energy from the Area EPS. This control mode is only beneficial to the interconnection customer if the electric service is on a retail time-of-use rate schedule. The example one-line of this type of control mode is shown in Figure 7.

Figure 7. Example of Typical One-line Diagram for Load Modify Control Mode



Appendix D – Simplified Diagrams for Various Rate Options

These on-line diagrams are simplified and do not include all relevant equipment. They are intended to depict metering configurations for the various options for qualifying facilities that are 100 kW or less in size.

Figure 8.(Drawing ME1I01) Qualifying Facility Average Retail Rate, Roll-over Credit, Time of Day, and Simultaneous Purchase and Sale Configurations

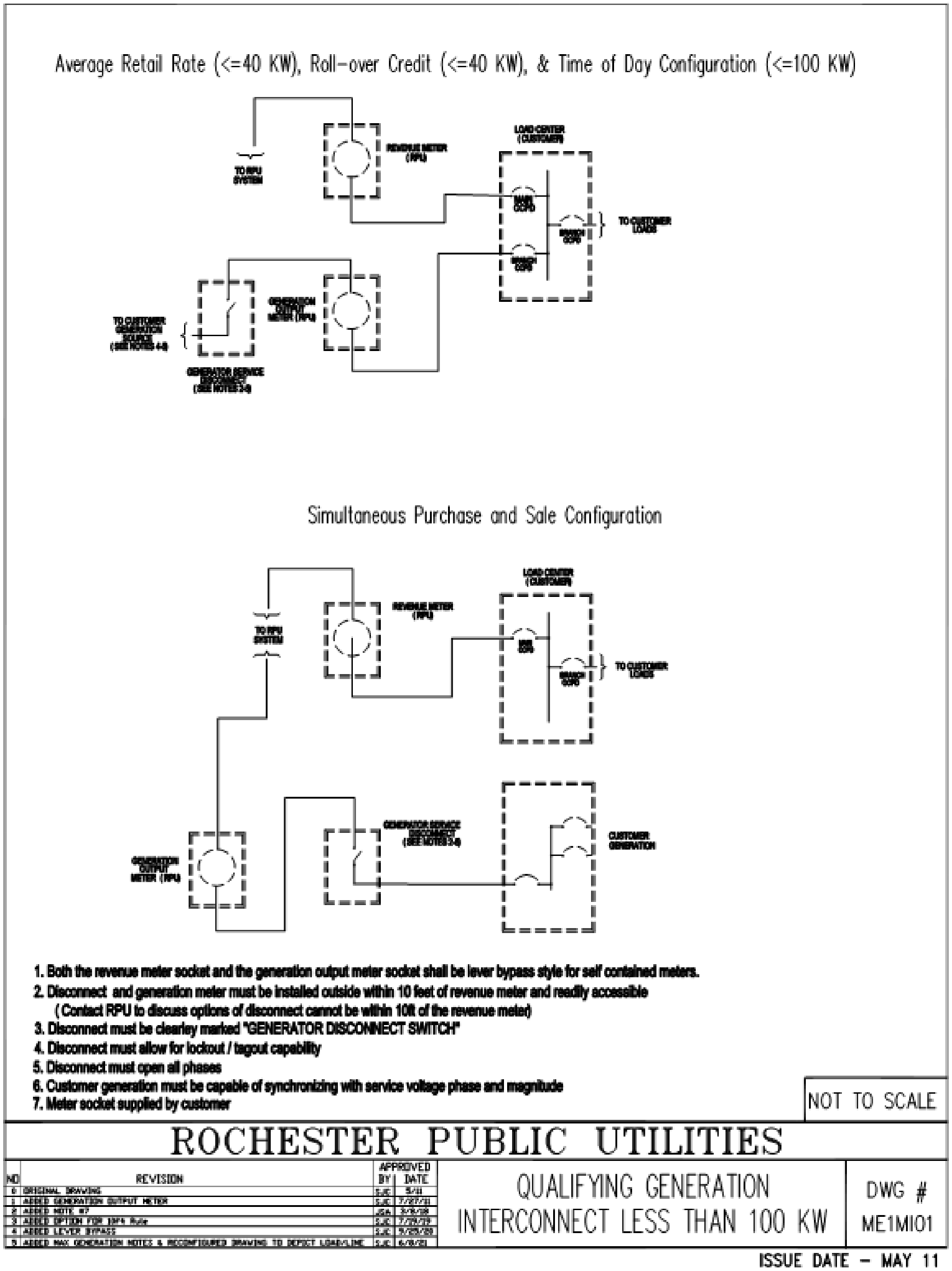


Figure 9. (Drawing ME1MI02) Non Qualifying Generation Interconnect Less than 40 KW

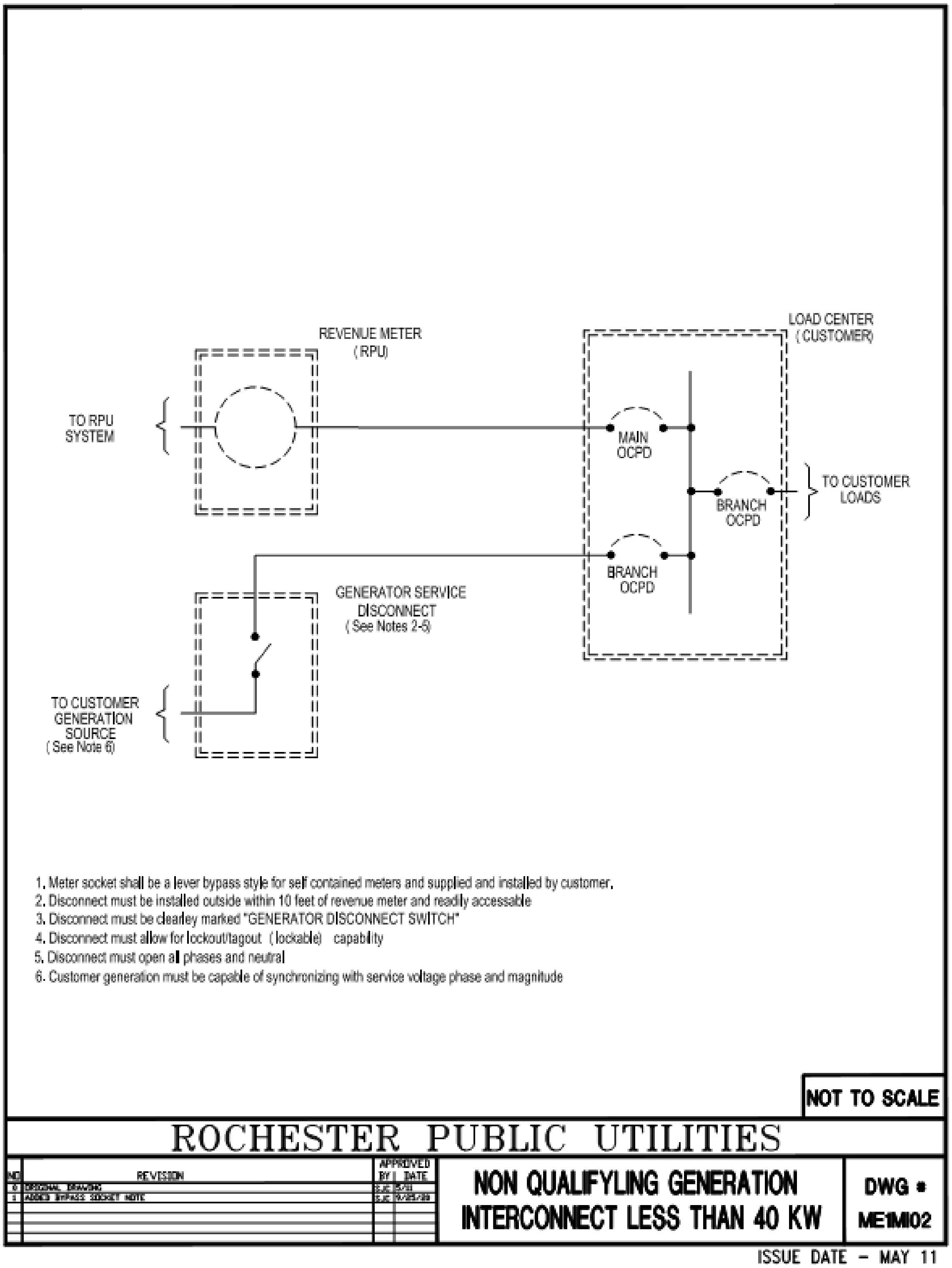


Figure 10. (Drawing ME1MI04) Qualifying Generation with Dual Fuel or Roll Over Credit

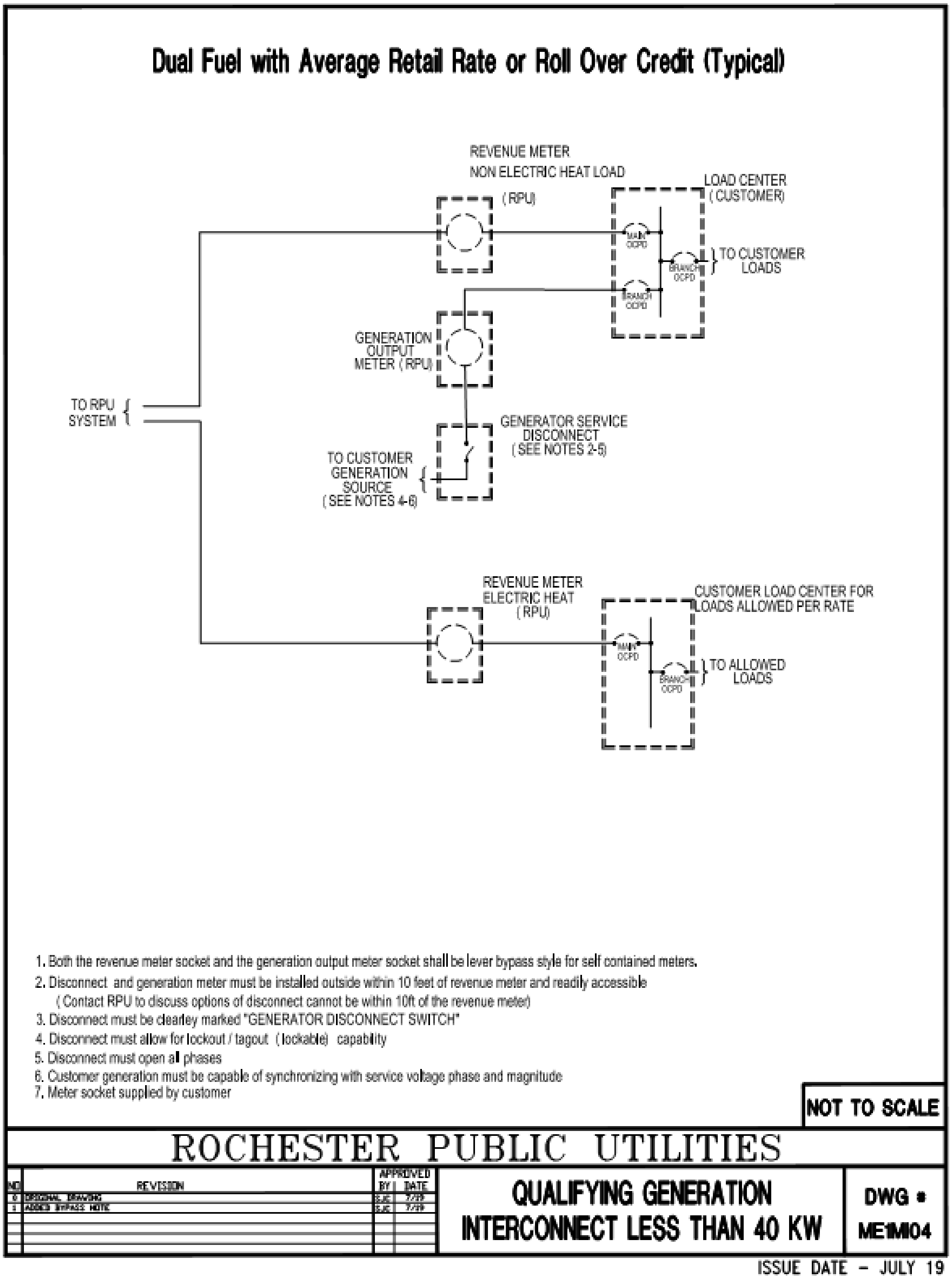
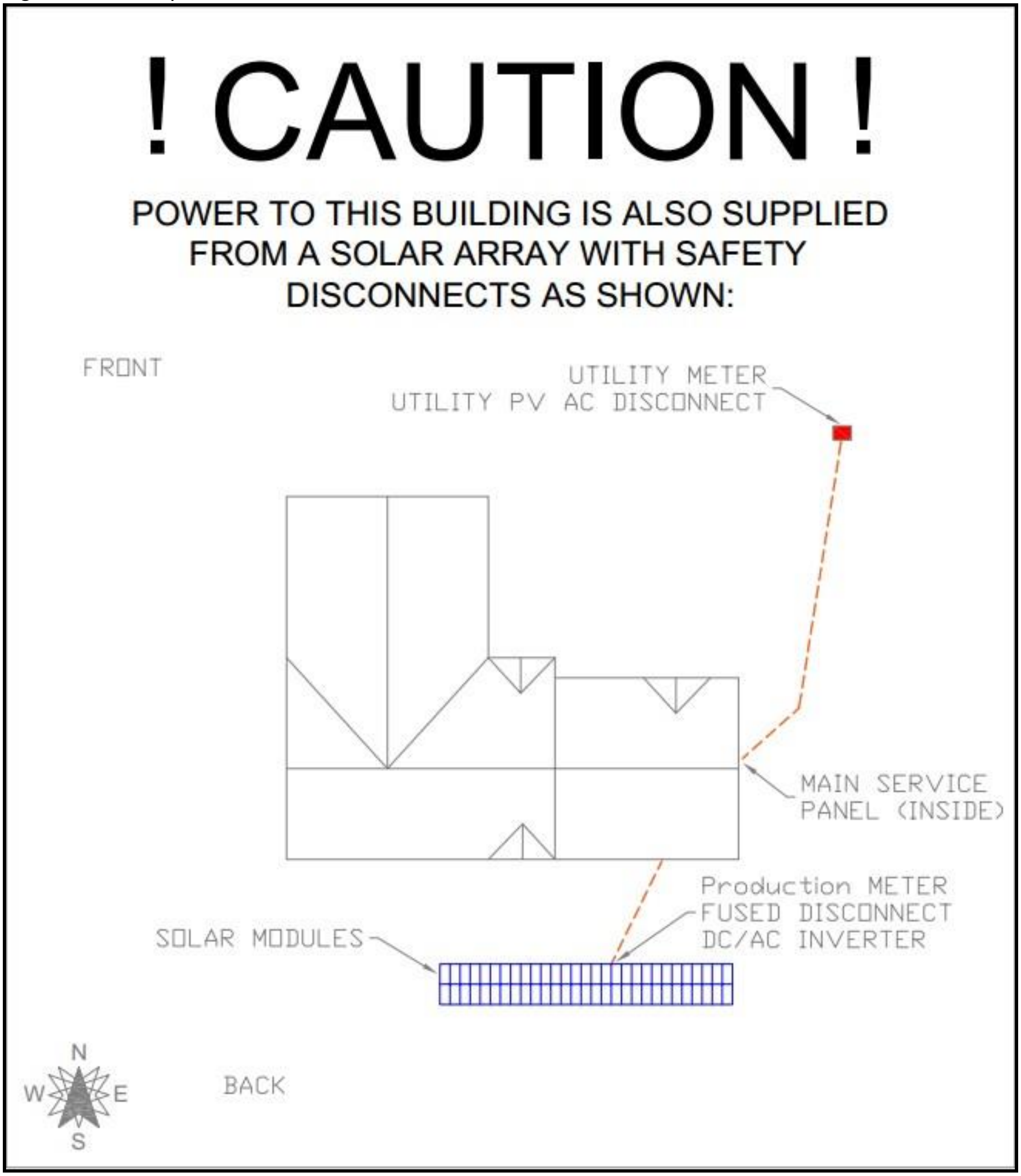


Figure 11. Example Placard



Appendix E – Certificate of Completion

Certification of Completion for RPU

The Interconnection Customer should complete the Distributed Energy Resource Certification of Completion for a proposed DER interconnection in the Simplified Process Track. As a condition of interconnection, a completed copy of this form must be returned to RPU.

Distributed Energy Resource Information			
Interconnection Customer:			
DER Project Address:			
City:		State:	Zip Code:
Application ID:	Meter Number:		
Is the DER system owner-installed?	☐ Yes ☐ No (If no please completed Installer Information)		

Installer Information	
Contact Name:	
Name of Business:	
Email:	Phone:
Electrician Name	License #

Electrical Permitting Authority	
The DER has been installed and inspected in compliance with the local electrical permitting authority ☐ Yes ☐ No	
If inverter based DER, the inverters are UL 1741 certified and have been programmed to have: ☐ Yes ☐ No Operating Mode set to Constant Power Factor with power factor set at 0.98 absorbing ☐ Yes ☐ No Frequency Abnormal Response set to IEEE 1547-2003 ranges ☐ Yes ☐ No Voltage Abnormal Response set to IEEE 1547-2003 ranges ☐ Yes ☐ No Dynamic Voltage Support and Volt-Watt is not active	
Installer Signature:	Date:
Please print clearly or type and return completed along with any additional documentation	

For Office Use Only
Date Received:

Appendix F – Example Simplified Process DER Testing Procedure

ROCHESTER PUBLIC UTILITIES
WE PLEDGE, WE DELIVER

Distributed Energy Resources (DER) Commission Test Checklist

For RPU personnel use only.

Date: ______________________________ **RPU Representative:** ___________________________________

Address: ____

☐ **1** Customer or customer representative is present for the testing. Three phase customers acknowledge that the system will be tested for loss of phase which may cause single phasing to non-generating equipment and that they accept this risk.

Name of representative: ____

DER company: ____

☐ **2** Testing procedure explained to customer or customer representative.

☐ **3** Remote Generator Disconnect(s) installed and labeled properly.

☐ **4** Main meter area signage installed identifying location of remote Generator Disconnect(s), if located other than within 10ft of main meter or within sight.

☐ **5** Disconnect the generator from utility system power and ensure the inverter(s) properly shutdown.

☐ **6** Reconnect the generator to utility system power by closing the disconnect switch and ensure the system does not re-parallel with the utility system for at least 5 minute once the switch was closed.

☐ **7** ***Three phase systems only:***
Disconnect one phase at a time

◯ All generation stopped after A phase was lost.
◯ All generation stopped after B phase was lost.
◯ All generation stopped after C phase was lost.

☐ **8** Production meter socket tested and production meter installed.

Production meter number: ____

☐ **PASS**

☐ **FAIL**

REASON FOR FAIL: ____

Page 1 of 1 • DER Commission Test Checklist • February 2021

Appendix F – DER Alteration Notification

This form is only applicable for installed DER systems that have prior approval from the Area EPS Operator to operate in extended parallel**. Changes to capacity size, type, technology or location should be applied as a new application using either the Simplified or Fast Track application forms**. This form is to inform the Area EPS Operator of changes in inverter, control system and protective device settings or the exchange of “like-for-like” DER equipment. The Area EPS Operator may determine the proposed change requires additional review to ensure the operation of the Area EPS is not detrimentally affected. The Area EPS Operator will notify the listed contact if additional details or steps are required. Contact the DER Coordinator for further information.

General Information		
Original Application ID (If known):		
Customer Account Number:		
Address of Generating Facility:		
City:	State:	Zip Code:
Existing DER System		
Current DER Type *(Check all that apply)*:		
☐ Solar Photovoltaic	☐ Wind	☐ Energy Storage
☐ Combined Heat and Power	☐ Solar Thermal	☐ Other (please specify)
Aggregate DER Capacity (the sum of nameplate capacity of all generation and storage devices at the PCC):		
kW_{ac}	*kVA_{ac}*	
Please, in detail, explain the proposed alteration to the DER system: *(Example: Existing inverter was replaced with 9.8 kW AC inverter, Solar Edge Model SE-9800-US. Settings remained the same in the inverter.) (Example: Plan to utilize Time-of-Use control mode of ESS. Also updated to firmware v2.3)*		
Contact for Additional Questions		
Name:		
Company Name:		
Email:	Phone:	

APPENDIX G: PV and Inverter-base DER Ground Referencing Requirements and Sample Calculations

Scope

This document lists technical requirements, and provides sample calculations, for ground referencing of inverter based Distributed Energy Resources (DER) on the Area EPS 4-wire system medium-voltage (MV) electric distribution system. DER units with AC nameplate capacities from 100kW to 10MW are covered in the scope. This document assumes a proper ground reference is being created by either a separate grounding transformer or a wye-grounded:delta (MV:LV) interconnection transformer. Inverters which have an internal grounded-wye isolation transformer are not covered in this document. The information in this document is to be applied at the Point of Common Coupling.

Background

Ground referencing electric distribution systems is standard practice in large part to avoid damaging overvoltages, for line-to-ground connected loads, which can result from ground fault conditions on ungrounded systems. Figure A below shows the range of expected line voltages for different system ground referencing methods. Line surge arrestors and customer equipment connected phase-to-ground are usually not designed to withstand the phase-to-phase voltages that can occur during ungrounded system fault conditions.

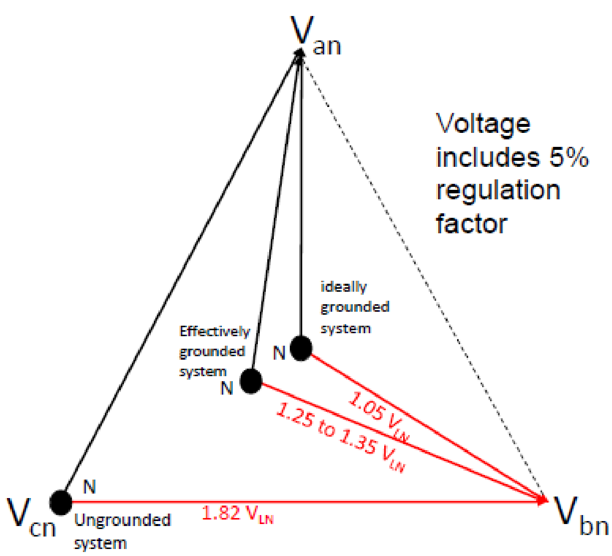


Figure A – Neutral shift during ground fault conditions

During a ground fault condition, in situations where the Area EPS's protective device opens and before the DER trips off-line, the distribution system has lost the system ground reference. It is important that any DER source energizing this portion of the distribution system provides a ground reference in order to prevent overvoltages.

Std IEEE 1547-2013 stated that "the grounding scheme of the DR interconnection shall not cause overvoltages that exceed the rating of the equipment connected to the Area EPS". Std IEEE 1547-2018 states that "The DER shall not cause the fundamental frequency line-to-ground voltage on any portion of the Area EPS that is designed to operate effectively grounded, as defined by IEEE Std C62.92.1, to exceed 138% of its nominal line-to-ground fundamental frequency voltage for a duration exceeding one fundamental frequency period." The below requirements for inverter ground referencing are adopted from IEEE P1547.8/D8- 2014 which is the draft document titled Draft Recommended Practice for Establishing Methods and Procedures that Provide Supplemental Support for Implementation Strategies for Expanded use of IEEE Standard 1547. Although this document as a whole is in draft form and not yet approved, the Area EPS believes the provision below on inverter ground referencing identifies a best practice.

Requirements

For DG Facilities with an Inverter Interface:

1) $X_{0,DG}$ = 0.6 p.u. +/- 10%   Note: 1 p.u. is based on $Z_{base} = \frac{kV^2}{MVA_{DER}}$
2) $\frac{X_{0.DG}}{R_{0,DG}} \geq 4$
3) Ground referencing equipment shall be designed to withstand a minimum of V0 = 4% and remain connected.

   Note: I_0 can be approximated as $I_0 = \frac{V_0}{Z_0}$

4) Ground referencing equipment shall have 5-second withstand ratings that exceed maximum available short-circuit current for close in faults.

Additional Notes:

- *a) Sum of MVA ratings of DER inverter nameplates and high-side (medium voltage) kV rating of interconnection transformer or grounding bank, depending on which unit creates the ground source, are used in determining required zero-sequence impedance (X0,DG) for composite facility.*
- *b) The MVA and high-side kV rating of the interconnection transformer or grounding bank, depending on which unit creates the ground source, is used for determining grounding bank and neutral reactor sizing.*
- *c) The impedance of the interconnection transformer is needed for neutral reactor sizing.*

Example Calculations

The below examples assume a ground reference is created by a proper transformer configuration and that the PV facility is interconnected to the Area EPS 4-wire electric distribution system. For simplicity, the example online diagrams below exclude system components not relevant to grounding requirements; these drawings are not intended to be used as example one lines for system design.

Example 1 – Separate Zig-Zag Grounding Transformer

A PV facility with 1 MVA inverter total AC nameplate is interconnected to a 13.8kV feeder through a 1 MVA interconnection transformer that does not create a ground reference. A separate zig-zag transformer is connected at 13.8kV to meet ground referencing requirements. (Note: Secondary ground bank connections are also acceptable when the interconnection transformer is wye-grounded:wye-grounded. The kV used for determine ZBase would be 480V in that case.)

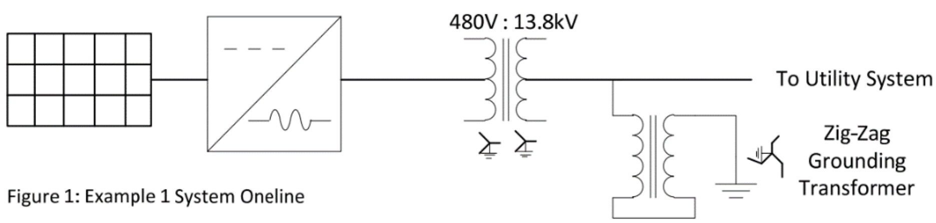


Figure 1: Example 1 System Oneline

1) Find base impedance:

$$Z_{BASE} = \frac{kV^2}{MVA_{pv}} = \frac{13.8^2 kV}{1MVA} = 190\ \Omega$$

Notes: kV is high-side voltage of grounding transformer, MVAPV is aggregate facility (i.e. 5 MVA would be used for five 1 MVA facilities)

Find zero-sequence reactance requirement:

$$X_{0,DG} = 0.6\ (190)\ \Omega \pm 10\% = 114\ \Omega \pm 10\%$$

The zig-zag grounding transformer will require a per phase zero-sequence reactance of 114 Ω ± 10 % to meet Requirement 1.

2) For Requirements 2, verify $\frac{X_{0,DG}}{R_{0.DG}} \geq 4$

3) For Requirement 3, assuming $X_{0,DG}$ = 114 Ω determines the continuous current associated with V_0 = 4%.

Find base current value

$$I_{BASE} = \frac{V_{BASE}}{Z_{BASE}} = \frac{\frac{13.8}{\sqrt{3}} kV}{190\ \Omega} = 41.8\ A$$

Find per unit zero sequence current

$$I_{0,p.u.} = \frac{V_0}{Z_0} = \frac{0.04}{0.6} = 0.067\ p.u.$$

Find zero sequence current in amps

$$I_0 = I_{BASE} * I_{0,p.u.} = 41.8A * 0.067 = 2.8\ A$$

Verify that the transformer per phase rating exceeds this value.

Find neutral current

$$I_N = 3(I_0\ ) = 3(2.8)A = 8.4\ A$$

Verify that the transformer continuous neutral rating exceeds this value.

4) For Requirement 4, request system impedance from the Area EPS engineer and determine ground bank's short circuit contribution for close-in single-line to ground faults. The grounding transformer 5-second withstand rating shall exceed the maximum anticipated ground fault current contribution from the transformer.

Example 2 – Wye-grounded: Delta Interconnection Transformer with Neutral Rector

A PV DER facility with a 1 MVA inverter total AC nameplate is interconnected to a 13.8 kV feeder through a 1 MVA interconnection transformer through a wye-grounded:delta interconnection transformer (grounded-wye winding is connected to 13.8 kV system). The interconnection transformer has nameplate impedance of 5%. A neutral reactor is required to meet ground referencing requirements.

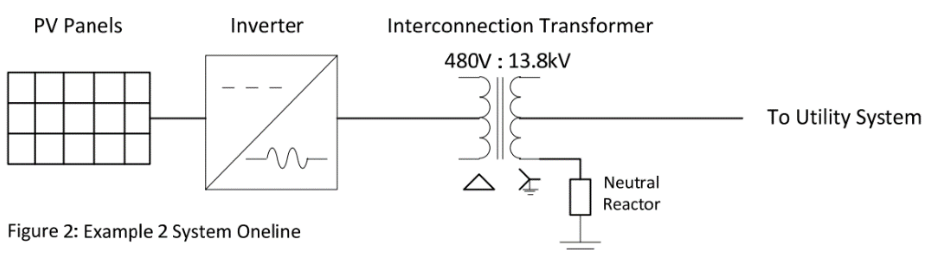


Figure 2: Example 2 System Oneline

1) Find base impedance:

$$Z_{BASE} = \frac{kV^2}{MVA_{pv}} = \frac{13.8^2 kV}{1MVA} = 190\ \Omega$$

Note: kV is high-side voltage of grounding transformer, MVA PV is aggregate facility (i.e. 5 MVA would be used for five 1 MVA facilities)

Find zero-sequence reactance requirement:

$$X_{0,DG} = 0.6\ (190)\ \Omega \pm 10\% = 114\ \Omega \pm 10\%$$

Find interconnection zero-sequence reactance contribution:

$$X_{0,Xfmr} = X_{0,Xfmr,p.u.} * Z_{Base} = 0.05\ (190)\ \Omega = 9.5\ \Omega$$

Find neutral reactor zero-sequence contribution to meet requirement for subtracting interconnection transformer contribution:

$$X_{0,NR} = X_{0,DG} - X_{0,Xfmr} = 114 - 9.5\ \Omega = 104.5\ \Omega \pm 10\%$$

Determine neutral reactor size (note: INeutral = 3 * I0,Xfmr):

$$X_{NR} = \frac{X_{0,NR}}{3} = \frac{104.5\ \Omega}{3} = 34.8\ \Omega\ \pm 10\%$$

A neutral reactor with a reactance of 34.8 Ω ±10%, inserted into the neutral of the interconnection transformer, will meet ground referencing Requirement 1. Requirement 2 through 4 should be checked using transformer nameplate information.

2) For Requirements 2, verify $\frac{X_{0,DG}}{R_{0,DG}} \geq 4$

3) For Requirement 3, assuming $X_{0,DG} = 114\ \Omega$ determines the continuous current associated with $V_0 = 4\%$

   Find base current value

$$I_{BASE} = \frac{V_{BASE}}{Z_{BASE}} = \frac{\frac{13.8}{\sqrt{3}}\,kV}{190\ \Omega} = 41.8\ A$$

   Find per unit zero sequence current

$$I_{0,p.u.} = \frac{V_0}{Z_0} = \frac{0.04}{0.6} = 0.067\ p.u.$$

   Determine zero sequence current in amps

$$I_0 = I_{BASE} * I_{0,P.u.} = 41.8\ A * 0.067 = 2.8\ A$$

   Find neutral current

$$I_{NR} = 3(I_0)\ A = 8.4\ A$$

   Verify that the neutral reactor continuous rating exceeds this value.

4) For Requirement 4, request system impedance from the Area EPS engineer and determine ground bank's short circuit contribution for close-in single-line to ground faults. The grounding transformer 5-second withstand rating shall exceed the maximum anticipated ground fault current contribution from the transformer.

Example 3 – Separate Wye-grounded: Delta Grounding Transformer

A PV facility with 1MW inverter total AC nameplate is interconnected to a 13.8kV feeder through a 1MVA wye-grounded:wye-grounded interconnection transformer. A separate wye-grounded:delta_transformer is connected at 480V to meet grounding reference requirements.

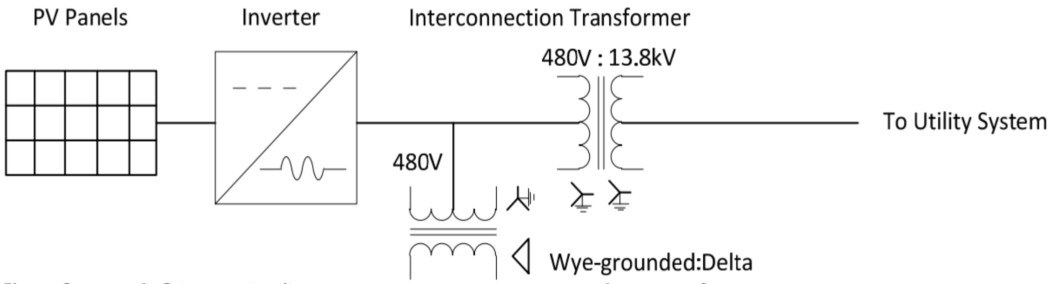


Figure 3: Example 3 System Oneline

1) Find base impedance:

$$Z_{BASE} = \frac{kV^2}{MVA_{pv}} = \frac{0.48^2 kV}{1MVA} = 0.2304\ \Omega$$

Notes: kV is high-side voltage of grounding transformer. MVAPV is aggregate facility (i.e 5MVA would be used for five 1 MVA facilities)

Find zero-sequence reactance requirement:

$$X_{0,DG} = 0.6\ (0.23)\ \Omega \pm 10\% = 0.14\ \Omega \pm 10\%$$

The grounding transformer will require a per phase zero-sequence reactance of 0.14Ω ±10% to meet requirement 1.

2) For Requirements 2, verify $\frac{X_{0,DG}}{R_{0,DG}} \geq 4$

3) For Requirement 3, assuming $X_{0,DG} = 0.14\ \Omega$ determines the continuous current associated with V_0 = 4%.

Find base current value

$$I_{BASE} = \frac{V_{BASE}}{Z_{BASE}} = \frac{\frac{0.48}{\sqrt{3}}kV}{0.2304\ \Omega} = 1202.8\ A$$

Find per unit zero sequence current

$$I_{0,p.u.} = \frac{V_0}{Z_0} = \frac{0.04}{0.6} = 0.067\ p.u.$$

Find zero sequence current in amps

$$I_0 = I_{BASE} * I_{0,P.u.} = 1202.8\ A * 0.067 = 80.6\ A$$

Verify that the transformer per phase rating exceeds this value.

Find neutral current

$$I_N = 3(I_0) = 3(80.6)\ A = 241.8\ A$$

Verify that the transformer continuous neutral rating exceeds this value.

4) For Requirement 4, request system impedance from the Area EPS engineer and determine ground bank's short circuit contribution for close-in single-line to ground faults. The grounding transformer 5-second withstand rating shall exceed the maximum anticipated ground fault current contribution from the transformer.

APPENDIX H: Area Eps Operator Required Profile For Inverter Based Der Systems

Utility Specified Settings for Inverters

Rochester Public Utilities has posted in the NOVA on-line application portal, a CSV file with these **specified settings** as shown below.

Also posted in the NOVA portal is a spreadsheet which can be used to provide the **Applied Settings** for the inverter. A table with notes on each of the required fields is included after the specified settings table.

Table 9 - Utility Specified Settings for Inverters

PARAMETER	VALUE
COMMENT	**THESE ARE THE UTILITY SPECIFIED SETTINGS**
MT_FILE_INFO_TYPE	SS
COMMENT	**THESE SETTING ARE APPLICABLE FOR THE FOLLOWING CONDITIONS**
MT_UTILITY_NAME	DAKOTA_ELECTRIC_ASSOCIATION
MT_COUNTRY	United States of America
MT_STATE	Minnesota
MT_APPLICABILITY_DATE	09/01/2023
MT_POWER_CONVERSION_ DEV-APP	INVERTER
MT_NP_NORMAL_OP_ CAT- APP	CAT_B
MT_NP_ABNORMAL_OP_ CAT-APP	CAT_III
MT_NP_P_MAX-MIN-APP	0.0
MT_NP_P_MAX-MAX-APP	1000000
MT_PRIMARY_POWER_ SOURCE	SOLAR-WIND-HYDRO
COMMENT	**ENTER_ SERVICE_PARAMETERS (1547 Defaults)**
ES_PERMIT_SERVICE-SS	ENABLED
ES_V_LOW-SS	0.917
ES_V_HIGH-SS	1.05
ES_F_LOW-SS	59.5
ES_F_HIGH-SS	60.1
ES_DELAY-SS	300
ES_RANDOMIZED_DELAY- SS	0
ES_RAMP_RATE-SS	300
COMMENT	**CONSTANT_POWER_FACTOR_MODE_ PARAMETERS**
CONST_PF_MODE_ENABLE- SS	DISABLED
CONST_PF_EXCITATION-SS	ABS
CONST_PF-SS	0.98

CONST_Q_MODE_ENABLE- SS	DISABLED
CONST_Q-SS	0
COMMENT	**VOLT-VAR_MODE_PARAMETERS (1547 STANDARD VALUES)**
QV_MODE_ENABLE-SS	ENABLED
QV_VREF-SS	1.0
QV_VREF_AUTO_MODE-SS	DISABLED
QV_VREF_TIME-SS	5
QV_CURVE_V1-SS	0.92
QV_CURVE_Q1-SS	0.44
QV_CURVE_V2-SS	0.98
QV_CURVE_Q2-SS	0.0
QV_CURVE_V3-SS	1.02
QV_CURVE_Q3-SS	0.0
QV_CURVE_V4-SS	1.08
QV_CURVE_Q4-SS	-0.44
QV_OLRT-SS	5
COMMENT	**WATT-VAR_CONTROL_PARAMETERS**
QP_MODE_ENABLE-SS	DISABLED
COMMENT	**VOLT-WATT_CONTROL_PARAMETERS (1547 STANDARD VALUES)**
PV_MODE_ENABLE-SS	ENABLED
PV_CURVE_V1-SS	1.06
PV_CURVE_P1-SS	1.0
PV_CURVE_V2-SS	1.10
PV_CURVE_P2-SS	0.0
PV_OLRT-SS	10
COMMENT	**OVER_UNDER_VOLTAGE_MUST_TRIP_PARAMETERS (MISO RECOMMENDED VALUES)**
OV2_TRIP_V-SS	1.20
OV2_TRIP_T-SS	0.16
OV1_TRIP_V-SS	1.10
OV1_TRIP_T-SS	2.0
UV1_TRIP_V-SS	0.70
UV1_TRIP_T-SS	5.0
UV2_TRIP_V-SS	0.45
UV2_TRIP_T-SS	0.32
COMMENT	**OVER_UNDER_FREQUENCY_MUST_TRIP_PARAMETE RS (MISO RECOMENDED VALUES)**
OF2_TRIP_F-SS	62.0
OF2_TRIP_T-SS	0.16
OF1_TRIP_F-SS	61.2
OF1_TRIP_T-SS	300.0
UF1_TRIP_F-SS	58.5

UF1_TRIP_T-SS	300.0
UF2_TRIP_F-SS	56.5
UF2_TRIP_T-SS	0.16
PF_DBOF-SS	0.036
PF_DBUF-SS	0.036
PF_KOF-SS	0.05
PF_KUF-SS	0.05
PF_OLRT-SS	5.0

The following is the Applied Settings table. A CSV file with these fields completed is required to be provided to the utility to confirm the inverter configuration and to document the settings. **Information for all parameters is required unless the parameter name is listed in italics.**

For string inverters, where all string inverts have the same settings applied, only one CSV file is required from one of the string inverters to represent all the inverter configurations and settings.

Table 10- Vendor Applied Settings File

PARAMETER	VALUE	Notes
COMMENT	**THIS FILE IS THE AS-SET OR -AS FILE FOR THE INSTALLATION**	
MT_FILE_INFO_TYPE	AS	Context of the data in the file - SS is the utility specified settings file -AS is the returned As Set file
COMMENT	**BASIC_INVERTER_INFORMATION**	
NP_P_MAX		Active power rating in watts at unity power factor
NP_P_MAX_OVER_PF		Active power rating in watts at specified over-excited power factor
NP_OVER_PF		Over-excited power factor (VArs injected)
NP_P_MAX_UNDER_PF		Active power rating in watts at specified under-excited power factor
NP_UNDER_PF		Under-excited power factor (VArs absorbed)
NP_VA_MAX		Maximum apparent power rating in volt-amperes
NP_NORMAL_OP_CAT	CAT_B	Normal operating performance category
NP_ABNORMAL_OP_CAT	CAT_III	Abnormal operating performance category
NP_Q_MAX_INJ		Maximum injected reactive power rating in volt-amperes reactive
NP_Q_MAX_ABS		Maximum absorbed reactive power rating in volt-amperes reactive
NP_P_MAX_CHARGE		Maximum active power charge rating in watts
NP_APPARENT_POWER_ CHARGE_MAX		Maximum apparent power charge rating in volt-amperes. May differ from the apparent power maximum rating
NP_AC_V_NOM		Base nominal AC voltage rating in RMS Vac
NP_AC_V_MAX		Maximum output RMS AC voltage (VH) in the continuous operating region
NP_AC_V_MIN		Minimum output RMS AC voltage (VL) in the continuous operating region
NP_SUPPORTED_MODES	QV-QP-PV-CONST_PF-CONST_Q-PF	Indication of support for each control mode function separated by dashes
NP_REACTIVE_SUSCEPTANCE		Reactive susceptance that remains connected to the Area EPS in the cease to energize and trip state

NP_MANUFACTURER		Manufacturer
NP_MODEL		Model
NP_SERIAL_NUM		Serial number
NP_FW_VER		Firmware version
AP_LIMIT_ ENABLE		Limit active power function ENABLED or DISABLED
AP_LIMIT		Active power limit setting. Per unit value based on NP_P_MAX or NP_P_MAX_CHARGE. Negative values indicate active power absorption
COMMENT	**ENTER_ SERVICE_PARAMETERS (1547 Defaults)**	
ES_PERMIT_SERVICE-AS	ENABLED	Permit service function enable. This function is activated by request from the Area EPS Operator
ES_V_LOW-AS	0.917	Enter service voltage - low - setting. Per unit value based on NP_AC_V_NOM (voltage base)
ES_V_HIGH-AS	1.05	Enter service voltage - high - setting. Per unit value based on NP_AC_V_NOM (voltage base)
ES_F_LOW-AS	59.5	Frequency in Hz, and shall be reported to 3 decimal places
ES_F_HIGH-AS	60.1	Frequency in Hz and shall be reported to 3 decimal places.
ES_DELAY-AS	300.0	Minimum intentional enter service delay
ES_RANDOMIZED_DELAY-AS	300.0	Enter service randomized delay (optional feature in IEEE Std 1547-2018)
ES_RAMP_RATE-AS	300.0	Enter service soft-start duration in seconds. Time from zero to 100% of NP_P_MAX.
COMMENT	**CONSTANT_POWER_FACTOR_MODE_ PARAMETERS**	
CONST_PF_MODE_ENABLE-AS	DISABLED	Constant power factor mode enable.
CONST_PF_EXCITATION-AS		Under or over excited
CONST_PF-AS	0.98	Constant power factor setting, no sign should be used
CONST_Q_MODE_ENABLE-AS	DISABLED	Constant reactive power mode select.
CONST_Q-AS		Injecting reactive power setting. Per unit value based on NP_VA_MAX. Negative signs shall be used to indicate absorbing VAr.
COMMENT	**VOLT-VAR_MODE_PARAMETERS (1547 STANDARD VALUES)**	
QV_MODE_ENABLE-AS	ENABLED	Voltage-Reactive power mode enable.
QV_VREF-AS	1.0	Per unit value based on NP_AC_V_NOM (voltage base)
QV_VREF_AUTO_MODE-AS	DISABLED	Autonomous Vref adjustment enable.
QV_VREF_TIME-AS	5.0	Vref adjustment time constant in seconds as specified by the area EPS operator

QV_CURVE_V1-AS	0.92	Volt-VAr point V1 setting. Per unit value based on NP_AC_V_NOM.
QV_CURVE_Q1-AS	0.44	VArs at V1 setting. Per unit value based on NP_VA_MAX. Negative signs shall be used to indicate absorbing VAr.
QV_CURVE_V2-AS	0.98	Volt-VAr point V2 setting. Per unit value based on NP_AC_V_NOM.
QV_CURVE_Q2-AS	0.0	VArs at V2 setting. Per unit value based on NP_VA_MAX. Negative signs shall be used to indicate absorbing VAr.
QV_CURVE_V3-AS	1.02	Volt-VAr point V3 setting. Per unit value based on NP_AC_V_NOM.
QV_CURVE_Q3-AS	0.0	VArs at V3 setting. Per unit value based on NP_VA_MAX. Negative signs shall be used to indicate absorbing VAr.
QV_CURVE_V4-AS	1.08	Volt-VAr point V4 setting. Per unit value based on NP_AC_V_NOM.
QV_CURVE_Q4-AS	-0.44	VArs at V4 setting. Per unit value based on NP_VA_MAX. Negative signs shall be used to indicate absorbing VAr.
QV_OLRT-AS	5.0	Volt-VAr open-loop response time
COMMENT	**WATT-VAR_CONTROL_PARAMETERS**	
QP_MODE_ENABLE-AS	DISABLED	Active power-Reactive power mode enable.
COMMENT	**VOLT-WATT_CONTROL_PARAMETERS (1547 STANDARD VALUES)**	
PV_MODE_ENABLE-AS	ENABLED	Voltage-Active power mode enable
PV_CURVE_V1-AS	1.06	Volt-Watt point V1 setting. Per unit value based on NP_AC_V_NOM.
PV_CURVE_P1-AS	100.0	Watts at point V1 setting. Per unit value based on NP_P_MAX.
PV_CURVE_V2-AS	1.10	Volt-Watt point V2 setting. Per unit value based on NP_AC_V_NOM.
PV_CURVE_P2-AS	0.0	Watts at point V2 setting. Per unit value based on NP_P_MAX or NP_P_MAX_CHARGE. Negative values indicate active power absorption.
PV_OLRT-AS	10.0	Volt-Watt - Open loop response time

COMMENT	OVER_UNDER_VOLTAGE_MUST_TRIP_PARAMETERS (MISO RECOMMENDED VALUES)	
OV2_TRIP_V-AS	1.20	OV2 must trip over-voltage setting. Per unit value based on NP_AC_V_NOM.
OV2_TRIP_T-AS	0.16	OV2 must trip duration setting
OV1_TRIP_V-AS	1.10	OV1 must trip over-voltage setting. Per unit value based on NP_AC_V_NOM.
OV1_TRIP_T-AS	2.0	OV1 must trip duration setting
UV1_TRIP_V-AS	0.70	UV1 must trip under-voltage setting. Per unit value based on NP_AC_V_NOM.
UV1_TRIP_T-AS	5.0	UV1 must trip duration setting
UV2_TRIP_V-AS	0.45	UV2 must trip under-voltage setting. Per unit value based on NP_AC_V_NOM.
UV2_TRIP_T-AS	0.32	UV2 must trip duration setting
COMMENT	**OVER_UNDER_FREQUENCY_MUST_TRIP_PARAMETERS (MISO RECOMENDED VALUES)**	
OF2_TRIP_F-AS	62.000	OF2 must trip over-frequency magnitude setting. Frequency values shall be reported to 3 decimal places.
OF2_TRIP_T-AS	0.16	OF2 must trip duration setting
OF1_TRIP_F-AS	61.200	OF1 must trip over-frequency magnitude setting. Frequency values shall be reported to 3 decimal places.
OF1_TRIP_T-AS	300.0	OF1 must trip duration setting
UF1_TRIP_F-AS	58.500	UF1 must trip under-frequency magnitude setting. Frequency values shall be reported to 3 decimal places.
UF1_TRIP_T-AS	300.0	UF1 must trip duration setting
UF2_TRIP_F-AS	56.500	UF2 must trip under-frequency magnitude setting. Frequency values shall be reported to 3 decimal places.
UF2_TRIP_T-AS	0.16	UF2 must trip duration setting
PF_DBOF-AS	0.036	Over frequency deadband offset from nominal frequency in Hz. Frequency values shall be reported to 3 decimal places.
PF_DBUF-AS	0.036	Under frequency deadband offset from nominal frequency in Hz. Frequency values shall be reported to 3 decimal places.
PF_KOF-AS	0.05	Over frequency per unit frequency change corresponding to a 1 per unit power change (frequency droop).

PF_KUF-AS	0.05	Under frequency per unit frequency change corresponding to a 1 per unit power change (frequency droop).
PF_OLRT-AS	5.0	Frequency-Active power open-loop response time