Distributed Energy Resource Technical Specifications Manual

Review and Approval				
REV	**Prepared By**	**Date**	**Approved By**	**Date**
A	DFJ &HJA	5/17/2022	DFJ	6/22/2022
B	DFJ & HJA & DML	7/13/2022	DFJ	7/13/2022

Table of Contents

1. Introduction

The purpose of this Technical Specifications Manual (TSM) is to outline the technical requirements for safe and effective interconnection of Distributed Energy Resources (DERs) either interconnected to the Rock Energy Cooperative (Utility) electric distribution system or connected to the electric facilities of the Utility's electric customer. The Utility's electric distribution system is referred to as the Area Electric Power System (Area EPS) and the electric customer system is referred to as the Local Electric Power System (Local EPS).

DER facilities includes electric generators, battery energy storage systems, and other devices that can be a source of electric power and is ultimately connected in parallel for more than 100 milliseconds, or more than six cycles, to the Area EPS. The Area EPS owned by the Utility is a multi-grounded neutral system energized at a nominal voltage of 7.2/12.47 kV. The way a DER is connected to, and disconnected, from the Area EPS can vary.

This TSM generally applies to proposed new DER interconnections. It is intended to provide technical requirements for a typical interconnection. The Utility will work with the Customer to apply this manual on a case-specific basis depending on project and location details.

1.1. System Impact to Area EPS

Parallel DER facilities connected to the Area EPS can cause a variety of system impacts. Those located individually on higher capacity feeders or circuits may not cause very serious impacts whereas those located on weaker circuits, in aggregation or in special cases (such has lightly loaded conditions) can significantly impact the Area EPS. The interconnection of all parallel DER facilities requires safeguards for synchronization and integration. Further, from the Area EPS perspective, the challenges posed by any given parallel DER facility's interconnection do not diminish significantly with reduction in the facility size. For this reason, each specific interconnection must be studied with respect to its size, its type, and the nature of the Area and Local EPS at the interconnection point. Typically, some level of an interconnection or system impact study will be performed by the Utility of the proposed DER to identify any potential complications. The intent of this study is to avoid adverse impacts to the Area and Local EPS by identifying the impact(s) that will occur under normal and N-1 conditions. Where adverse system impacts are identified, the Utility will determine the required system modifications that can be implemented to mitigate the issue(s).

1.2. Potential Issues

The TSM, in combination with the Utility's interconnection or system impact study, is intended to prevent potential issues. There are a wide range of potential issues associated with the interconnection of DER facilities to the Area EPS including, but not limited to:

- Thermal overloads
- Impact on step voltage regulation equipment

- Increased fault duty on the Area EPS equipment
- Interference with the operation of protection systems
- Harmonic distortion contributions
- Steady state voltage outside of ANSI standards
- Voltage flicker
- Ground fault overvoltage
- Risk of unintentional islanding
- System restoration
- Power system stability
- System reinforcement
- Metering
- Arc flash

1.3. General Requirements

All parallel DER systems shall be designed to ensure:

- Capability to synchronize with the Area EPS.
- Capability to separate from the Area EPS upon loss of the Utility source.
- No degradation of the Area EPS safety and reliability.
- All energy supplied to the Area EPS will meet the Utility’s power quality and transmission system operator requirements.

1.4. On-going Responsibility

The Interconnection Customer (IC) shall be responsible for on-going compliance with regulatory, code, and system design and operating changes pertaining to their installation. This work will be performed at the cost of the IC. The Utility requires all electrical and physical design documents and submittals for DER interconnections with the Area EPS at 600 volts or above to be prepared and sealed by a State-Licensed Professional Engineer in the state where the installation is made, and who is retained by the IC for that purpose.

2. Interconnection Policy

The Utility's interconnection policy permits an IC to operate DER in parallel with the Utility's Area EPS, providing it can be done safely. The Utility strives to provide a safe and reliable interconnection and to carry out the interconnection process in a timely manner.

- All services must meet all applicable requirements of the Utility.
- All DER facilities will require an approved application and a fully executed interconnection agreement.
- All DER facilities sized to sell energy back to the Utility will be required to sign a Power Purchase Agreement (PPA).

- Single-phase and three-phase customer-owned DER may be connected in parallel with the Utility's Area EPS providing these facilities meet the requirements outlined in this manual.
- The Utility will reserve the right to open the inter-tie to and DER facility who violates the requirements outlined in this manual.
- The Utility shall not assume any responsibility for the protection of the DER facility, or any other customer's equipment within the Local EPS. The IC shall be completely responsible for protecting their system from any abnormalities.

3. Applicable Codes, Standards, and Guidelines

The DER system shall conform to the latest revision of all local, state, and federal codes and national standards that apply; including issued amendments unless the Utility has taken exception to such standard. Specific codes and standards applicable to this manual include, but are not limited to:

- Institute of Electrical and Electronics Engineers (IEEE) Std. 1547-2018 "Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power System Interfaces"
- Underwriters Laboratories (UL) Std. 1741 "Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources"
- ANSI/IEEE C2 "National Electrical Safety Code®" (NESC)
- NFPA 70 "National Electrical Code®" (NEC)
- NFPA 70B "Recommended Practice for Electrical Equipment Maintenance"
- NFPA 70E "Standard for Electrical Safety in the Workplace"
- NETA-MTS "Maintenance Testing Specifications for Electric Power Distribution Equipment and Systems"
- ANSI C84.1 Electric Power Systems and Equipment – Voltages Ranges

4. Performance Categories Assignment

Performance categories describe minimum equipment capability and the required ranges of allowable settings.

IEEE-1547-2018 standard provides a technology-neutral approach in which performance categories are assigned to specify required capability for reactive power performance, voltage regulation performance, and response to abnormal conditions.

There are several available performance categories defined in IEEE 1547 standard which contemplates current and future system needs at varying levels of DER penetration. Performance requirements associated with performance categories are driven by Area EPS or Regional Transmission Operator (RTO) needs. The subsections below contain the specific requirements that have been determined to be appropriate for application in the Utility's service territory.

4.1. Normal Condition – Category A and B

Category A and B specify reactive power capability and voltage regulation performance requirements. Category B is intended for use where DER penetration has the potential to be higher and where the DER power output is subject to frequent large variations. Category B encompasses all of Category A capabilities. Category A and B assignment is specified below.

DER Type	IEEE 1547-2018 Category
Synchronous Machine	Category A
Inverter-Based	Category B

4.2. Abnormal Condition – Categories I, II or III

Abnormal condition category assignments will not be enforced until mandated by the Regional Transmission Operator (RTO) and Bulk Power System (BPS).

DER capable of meeting abnormal performance categories outlined in IEEE 1547-2018 are encouraged to use Category I for synchronous machines and Category II for inverter-based generation.

Categories I, II, and III differentiate performance requirements for DER response to abnormal conditions. These requirements are specified below. Category III is the highest capability and can inherently meet the ride-through requirements of the lower categories. In contrast, the voltage and frequency trip requirements of higher categories may not be met by lower categories as the range of allowable settings may be mutually exclusive.

- Category I encompasses minimum BPS essential needs.
- Category II coordinates with North American Electrical Reliability Corporation (NERC) PRC-024-2 with a modification to the voltage ride-through in order to account for characteristics of distribution load devices.
- Category III covers all BPS reliability needs and also introduces ride-through requirements aimed at addressing high DER penetration integration issues such as power quality events and other abnormal system conditions which may arise from DER tripping in the Local EPS.

4.3. Default Parameters

The DER shall use the IEEE 1547 default parameter settings for all capabilities and performance requirements of the applicable performance category. In order to protect the Area EPS and BPS reliability and to produce a response from DER that can be modeled, deviating from the IEEE 1547-2018 default parameters for abnormal performance category settings should be a rare occurrence.

4.4. Alternative Abnormal Operating Performance Category

Desired performance outside of what is defined in this document will require study and agreement between the Utility and the IC. Mitigation of abnormal operating conditions may be required at the expense of the IC.

5. Power Factor Capability and Voltage/Power Control Performance

5.1. Constant Power Factor

All new DER interconnections shall be capable of providing a constant fixed power factor from 90% leading (absorbing) to 90% lagging (injecting). The required constant fixed power factor will depend on the size, type, location, and studied impact. Typically, for larger DER installations, the fixed power factor value will be identified in the interconnection study process and may additionally be specified in the interconnection and operation agreement.

The default power factor setting for synchronous and inverter-based generation shall be set to 98% absorbing reactive power unless specified differently by the Utility.

Induction generators less than or equal to 200 kW may be allowed to operate with minimal power factor correction at 0.95 leading (absorbing vars). Induction generators greater than 200 kW must have the capability to expand power factor capabilities with external devices such as a Static VAR compensator (SVC).

5.2. Voltage and Power Control Performance

In addition to constant power factor functionality, the DER shall be capable of adjusting active and reactive power output to maintain the Area EPS voltage within thresholds designated by the Utility and IEEE 1547-2018. The DER shall not actively regulate the Area EPS voltage without the approval of the Utility. Voltage and power control functions shall be available by DER category as indicated in the following table.

Control Function	IEEE 1547-2018 Category
Constant Reactive Power Mode	Category A & B
Voltage-Reactive Power Mode	Category A & B
Voltage-Active Power Mode	Category B

Active Power-Reactive Power Mode	Category B

6. Response to Abnormal Conditions

Abnormal conditions can occur on the Area EPS or BPS. Under these abnormal conditions the DER shall respond appropriately. Currently IEEE 1547-2018 certified inverters are not readily available, therefore inverters certified to the requirements of, IEEE 1547a-2014 should be used under abnormal conditions. The settings in this Section are based on IEEE 1547-2003 and should be used. A certified installation will include an inverter where a nationally recognized testing laboratory certifies that the inverter meets the applicable type testing requirements of UL 1741 (January 17, 2001 revision) and is acceptable for interconnection, without additional protection systems, to the distribution system. Manufacturers having certified production facilities or proven production processes and quality control methods certified by a NRTL shall be allowed to use said approved practices and documentation for fulfilment of production test requirements. Further discussion on certified facilities is included in Section 17.

6.1. Voltage Disturbance Delay & Trip Times

The IC shall operate their DER to maintain the same voltage level as the Area EPS at the PCC/POI and voltage regulation is required to be in-service whenever the DER is synchronized to the system. Undervoltage and overvoltage functions are applied to prevent unintentional islanding operation during an islanding event. The IC must provide an automatic method of disconnecting their DER(s) from the Area EPS if the voltage cannot be maintained within the Utility's limits as stated in the following table.

Voltage Disturbance Delay and Trip Time				
Trip Function	Range		Clearing Time	
	Percentage	Voltage (@ 120 V Base)	Seconds	Cycles
OV2	> 120%	> 144	0.16	9.6
OV1	110% - 120%	132 - 144	1.0	60
No Action	88% - 110%	105.6 - 132	No Operation	
UV1	50% - 88%	60 – 105.6	2.0	120
UV2	< 50%	< 60	0.16	9.6

6.2. Frequency Disturbance Delay & Trip Times

The nominal frequency of the Area EPS is 60 Hz and is maintained within the limits of 59.3 - 60.5 Hz under normal steady-state operation. Under frequency and over frequency functions are applied to prevent unintended islanding operation. The IC shall provide an automatic disconnecting means from the Area EPS when DER falls outside the limits stated in the following table.

Frequency Disturbance Delay and Trip Time				
Trip Function	Range		Clearing Time	
	Percentage	Frequency (Hz)	Seconds	Cycles
OF2	> 103.3%	> 62.0	0.16	9.6
OF1	102.0% - 103.3%	61.2.0 – 62.0	300.0	18000
No Action	97.5% - 102.0%	58.5 – 61.2	No Operation	
UF1	94.2% - 97.5%	56.5 - 58.5	300.0	18000
UF2	< 94.2%	< 56.5	0.16	9.6

Larger DER units, including units above 10 MVA, may be required to have over/under frequency protective (device 81 O/U) relaying set points that coordinate with the BPS automatic underfrequency load shedding program (UFLS). The RTO UFLS program and the North American Reliability Corporation (NERC) reliability standard PRC 006 govern the requirements. These requirements are dynamic and adjust over time to meet changing system needs. Therefore, DER units that currently do not have ULFS requirements today may have to comply with future requirements, including smaller installations. DER facilities must not separate from the system until all underfrequency load shedding steps have operated.

6.3. Dynamic Voltage Support

Dynamic voltage support is currently not allowed and shall be disabled.

6.4. Governor Droop

All DER units greater than 200 kW with active governors should be operated in automatic mode unless directed otherwise by the Utility. To provide equitable and coordinated system response to load and generation imbalances, governor droop should be employed, and governors should not be blocked or operated with excessive dead-bands. Cogeneration units associated with an industrial process may not be able to provide a large signal response but are encouraged to have a small signal response active. The default droop setting is 5%.

7. Protection Requirements

7.1. Manual Disconnect Switch

A manual disconnecting device, capable of interrupting the rated DER and/or load current, accessible to the Utility’s personnel, and which can be locked open with a visible open for line clearances, must be provided. The visible open shall be viewable without unbolting covers or assistance from site personnel.

The switch must be accessible to the Utility's personnel without assistance from site personnel. The form of this device will vary with the service voltage and generator capacity.

The manual disconnect switch must be clearly marked with a permanent, weather-proof label. Unless given a written exception from the Utility, the manual disconnect switch must be located within 10 feet and a clear line of sight from the revenue meter. In cases where the Cooperative exception is granted and the switch and/or production meter are not located in close proximity to the Utility's revenue meter, the IC must post at the revenue meter a permanent, weather-proof, clearly labeled map or diagram showing the location of the revenue meter, the switch, production meter, and DER facility.

DER facilities that do not operate continuously in parallel with the Area EPS may omit the disconnect switch. To qualify, the IC system must be a separate system never in parallel, a high-speed transfer, or closed transition limited to a maximum of 2 minutes in parallel.

7.2. Protective Devices

Protective devices (relays, circuit breakers, etc.) for the protection of the Area EPS, metering equipment, and synchronizing equipment must be installed as required by the Utility and IEEE 1547-2018. The complexity of the protective devices differs with the size, complexity, and location of the generation installation.

7.3. Protective Relay Default Settings

For the protective functions required under IEEE 1547-2018, the default settings provided in IEEE 1547-2018 shall be used unless the interconnection review indicates some other setting is to be used. The exception is the underfrequency relay setting as previously discussed.

7.4. Protection Requirements by DER Size Classification

The Utility has established seven different classes of protective relaying for distribution interconnected generation. These are provided as guidance and are meant to be consistent with IEEE 1547-2018. IEEE 1547.2 provides additional discussion, design considerations, and approaches to address specific applications. The following table provides a summary of protection 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)**	**Sync-Check (25)**	**Transfer Trip**
20 kW and Under (Section 16 Figs. 1 & 2)	-	YES(1)	YES(1)	-	-	-	YES(1)	-
20 kW to 200 kW (Section 16 Figs. 3 & 4)	YES(1)	YES(1)	YES(1)	YES(1)(3)	-	-	YES(1)	-
200 kW to 1 MW (Section 16 Fig. 5)	YES(1)	YES(1)	YES(1)	YES(1)	YES	-	YES	YES(2)
1 MW to 10 MW (Section 16 Fig. 6)	YES(1)	YES(1)	YES(1)	YES(1)	YES	-	YES	YES(2)

>10 MW (Section 16 Fig. 7)	YES	YES	YES	YES	YES	-	YES	YES(2)
Hot Transfer Standby Generation	YES	YES	YES	YES	YES	YES	YES	YES(2)
Soft Loading Transfer System	YES(3)	YES(3)	YES(3)	YES(3)	YES(3)	YES	YES	YES(2)

(1) For systems with certified inverters, these functions may be built into the inverter.
(2) The need for transfer trip will be determined by the Utility when studied.
(3) The need for these protective elements will be reviewed by the Utility.

Where multiple DERs are connected to the Area EPS through a single service point, the class will be determined by the sum of the DER ratings. The classes are based upon generator or inverter nameplate ratings.

These classes have been established for convenience and are based on circuits with normal load density. The final decision as to the requirements for each installation will be made depending on IC load magnitude, the magnitude of other loads connected to that circuit or Area EPS, available short circuit contribution, source substation size, line conductor size, etc.

The noted protection is for the protection of the Area EPS and other customers connected to the Area EPS. In each application, protective relaying associated with the interface requirements will be reviewed by the Utility. The IC shall be responsible for determining their own relay settings. The IC should provide documentation that their interconnection relaying and settings are in accordance with these documents before the start of relay trip checks. Small certified interconnection packages up to 20 kW normally do not require relay setting determination.

Non-certified installations and DER facilities greater than 200 kW require utility grade relays. The following specifies what a utility grade relay should include:

- Meets or exceeds ANSI/IEEE Standards for protective relays (i.e., C37.90, C37.90.1, and C37.90.2).
- Extensive documentation covering application, testing, maintenance, and service.
- Positive indication of what caused a trip (Targets).
- A means of testing that does not require extensive unwiring (e.g. a draw out case, test blocks, FT- 1 switches, etc.)

7.4.1. Installations of 20 kW and Under

Most installations in this class feature a certified interconnection package. Each package will be reviewed by the Utility to verify that it is certified and applied in a manner consistent with its certification. Relay settings will be reviewed for inverters certified under IEEE 1547-2018.

Except for certified interconnection packages, all installations in this class will require a design and relay review by the Utility (i.e., metering and relaying one-lines, protection, and control schematics, relay setting sheets, and nameplate data of the generator(s), breaker(s), and disconnect switch(es)). The Utility will determine if a relay and site inspection (i.e., witnessing the calibration and testing of the relays and operation of the generator and breakers) is also required.

Stand-alone energy storage (battery) installations must be permanently wired into a suitable load center in accordance with the NEC (see Article 690 for PV and 702 for Standby). A lockable disconnect switch must be provided that is readily accessible to the Utility's personnel. This switch is to be at the metering point unless an alternate location is readily accessible and easily identifiable. The Utility must approve the alternate location and a durable map or written sign should be provided at the metering or PCC location indicating the location of the switch.

7.4.2. Installations of 20 kW to 200 kW

Except for certified interconnection packages, all installations in this class will require a design and relay review by the Utility (i.e., metering and relaying one-lines, protection, and control schematics, relay setting sheets, nameplate data of the generator(s), breaker(s), disconnect switch(es), and certified test reports). The Utility will determine if a relay and site inspection (i.e., witnessing the calibration and testing of the relays and operation of the generator and breakers) is required. Installations using certified interconnection packages do not require the full documentation; however, review of relay settings is required.

Installations that use a certified package will be given a quick review. All installations that are not a standard package must be reviewed individually. Some variation in the specifics of the requirements, but not the intent, will be allowed. The intent is to be consistent with IEEE 1547-2018 requirements. The Utility must approve all variations. Non-certified installations in this class may use either industrial grade or utility grade relays.

7.4.3. Installations from 200 KW to 1 MW

All non-certified installations in this class will require a design and relay review by the Utility (i.e., metering and relaying one-lines, three-lines, protection and control schematics, relay setting sheets, nameplate data of the generator(s) and breaker(s)/disconnect switch(es) and certified test reports will be provided to the Utility by the Customer. A site inspection (i.e., witnessing the calibration and testing of the relays and operation of the generator and breakers) is also required. The documentation and review can be reduced if certified interconnection packages are used. For this size range, the proposed relay settings must be provided for certified packages.

Installations in this size range may be an assembly of two or more certified interconnection packages. This is a common practice with photovoltaic sites. The certification process certifies the design and functionality for only one inverter package with its associated energy source. It does not address the increased system and protection impacts that multiple certified units will have. Because of this, a site with multiple packages must be reviewed and additional protective equipment and field-testing may likely be required for the larger composite installations. The use of certified inverters will reduce the time and cost of reviews and later commissioning.

With some of the larger installations, the IC instead of the Utility may own the transformer and associated equipment. Utility grade protective relays and utility grade equipment are required. The protective relaying aspects of certified interconnection packages are accepted as meeting the Utility grade requirement for that portion of the facility.

7.4.4. Installations from 1 MW to 10 MW

All installations in this class will require a design and relay review by the Utility (i.e., metering and relaying one-lines, three-lines, protection and control schematics, relay setting sheets, nameplate data of the generator(s) and breaker(s)/disconnect switch(es) and certified test reports will be provided to the Utility by the IC). A site inspection (i.e., witnessing the calibration and testing of the relays and operation of the generator and breakers) is also required.

Installations in this size range may be an assembly of multiple certified interconnection packages. This is a common practice with photovoltaic sites. The certification process certifies the design and functionality for only one inverter package with its associated energy source. It does not address the increased system and protection impacts that multiple certified packages will have. Because of this, a site with multiple packages must be reviewed and additional protective equipment and field-testing will likely be required. The use of certified inverters will reduce the time and cost of reviews and later commissioning.

Facilities in this size range are strongly encouraged to be located within two-line miles of the substation. Expensive system modifications and restrictive operating requirements become increasingly likely as the distance from the sub increases. Many rural systems will not accept this class of generation or may require extensive rebuilding and reinforcement, which would be completed at the IC's cost. The IC may be required to interconnect with the transmission system.

With some installations, the transformer and associated equipment are owned by the IC instead of the Utility. Utility grade protective relays and utility grade equipment are required.

7.4.5. Installations 10 MW and Above

In general, the Area EPS is designed to handle loads and DER up to 10 MW for urban/suburban circuits. Rural circuits are typically less than 10 MW. Installations greater than 10 MW are usually served from the sub-transmission (46 or 69 kV) or transmission (115 or 230 kV) system. DER facilities in excess of 10 MW are more likely to impact the Bulk Power System (BPS) and may be required to go through the FERC Small Generation Interconnection Process (SGIP).

7.4.6. Hot Transfer Standby Generation

A hot transfer standby DER system is defined as one in which an IC's generation can be connected to the Area EPS for more than 2 minutes but not on a continuous basis. These DERs fall under the same requirements as a DER that is continuously connected to the Area EPS. Since this type of installation often employs a sensitive direction power relay to aid in separation, some of the interconnection requirements may be relaxed, at the sole discretion of the Utility.

7.4.7. Soft Loading Transfer System

A soft transfer system is defined as one in which the paralleling of the Area EPS and the IC's DER equipment is less than 2 minutes. A soft or closed transfer is permitted for the purpose of avoiding excessive voltage and frequency deviations to the IC's load. Where the load is large, the transfers are to have a controlled ramp rate to avoid undue voltage disturbances to other customers. If the paralleling time has been exceeded, a breaker or switch must be automatically tripped to isolate the Area EPS from the IC's generators.

Because of the complexities in the closed transfer system(s), each installation will need to be reviewed on a case-by-case basis. Due to the brief nature of the paralleling exposure, reduced interconnection requirements may apply, such as waiving the effective grounding requirements in some cases. Machine based DER that will parallel for less than two-minutes and that will equal or exceed 1 MW of aggregated DER requires an approved application, engineering review, and a signed interconnection agreement. This size and type are likely to require voltage supervision of reclosing.

7.5. Additional Protection Requirements by Generation Type

7.5.1. Synchronous Generators

The Utility will review the settings of the IC's synchronizing relaying to verify the settings are within the guidelines of IEEE 1547-2018. This is to ensure settings suitable to prevent excessive voltage transients on the Area EPS are used. The Utility shall not take responsibility for the appropriateness of any given setting for protecting the IC's equipment. It is highly recommended that the IC consult with the manufacturer of their equipment for settings that are appropriate for the protection of the IC's equipment. Small interconnection facility packages that are certified for use with synchronous generators will include this functionality.

Sync-check relays (Device 25 or 25X) should be included in addition to the synchronizing relays on large synchronous generators. The 25X function should be a separate device (i.e., not included in the synchronizer) for all units 1 MW and above. The 25X, 25 relay, and any other sync relaying, must not allow the IC's facility to energize a de-energized utilities line. This is for the safety of the Utility personnel and the public. The maximum phase angle error and voltage difference allowed by the 25X relay, and other sync relaying as well, should be consistent with the guidelines in IEEE 1547-2018.

7.5.2. Induction Generators

Speed matching may be by any means such that voltage regulation and voltage flicker are held within the tolerances earlier described. Double-fed induction generators may behave similar to synchronous generators and need synchronizing relays similar to those required for synchronous generators.

For medium size induction generators (typically above 200 kW), a mechanical speed matching relay (device 15) set to accept mechanical speed within +3% of 60 Hz must be used. A +1% speed match band will be required for large induction generators. The largest effect on the system of bringing an induction generator to synchronous speed is the voltage drop associated with the magnetizing inrush current upon connection to the Area EPS.

7.6. Transfer Trip Considerations

Transfer trip (TT) is a protection method whereby the conditions at one location causes a signal to be sent via a high speed communication channel to another location resulting in a breaker trip or some other form of separation from the Area EPS to occur. For DER installations, the originating event is usually the feeder breaker at the substation tripping with the high speed signal being sent to the DER to cause separation from the distribution feeder. The TT may originate on the transmission system for high penetration situations, especially if the substation is supplied where no transmission voltage circuit breakers are present. TT is mainly used when studies indicate local anti-islanding protection is marginal or inadequate to ensure a timely disconnection to adequately protect the other customers on the feeder. The DER may desire this protection to protect a large rotating generator from damage.

For smaller DER and lower penetrations, TT is rarely needed since large rotating generators are typically not included. Since the DER's receiver must be connected to the feeder breaker and since feeders are field switched, especially during contingencies, TT requires that the communications path to the new source is established using pre-installed transmitters, adding cost and complexity to the installation. When large rotating generators are included, TT will be necessary for many of the situations. While uncommon, TT may be needed for large inverter-based facilities even without any rotating machines present.

7.7. Open Phase Protection

The DER shall detect and cease to energize all phases to which the DER is connected for an open phase condition on the Area EPS occurring directly at the reference point of applicability. The requirement to cease to energize for a single-phase condition shall apply to both three-phase inverters and three-phase installations made up of single-phase inverters. As required by IEEE 1547-2018, the DER shall detect and cease to energize for unintentional islands. When restoring output after momentary cessation, the restore output settings of the DER shall be coordinated with the Area EPS reclosing timing.

7.8. DC Fusing

Larger DER installations must have some form of interconnection facility protection redundancy to ensure that a single failure does not disable all interconnection protective relaying and separation functions. For larger facilities, the use of a single, fused DC relaying string is not allowed. Adequate protection for the loss of a DC fuse must be provided. A loss of potential scheme shall be used when a duplicate relay scheme or package is not used. Due to the severe consequences that may occur for a large DER unit if all protective relaying is lost due to a blown fuse, some form of redundancy is required.

7.9. Grounding

The Area EPS is an effectively grounded system and requires that the DER connected to the Area EPS be designed (through the selection of transformers, generator grounding, etc.) so that they contribute to maintaining an effectively grounded system in conformance with IEEE 1547-2018. A DER facility that does not participate in maintaining effective grounding, upon islanding, can cause severe over-voltages to single-phase loads, resulting in equipment damage. IEEE 1547.2 provides additional discussion on the importance of and methods to address effective grounding. If Inverter-based DER facilities and the aggregate of the distribution feeder are under 200 kW or below the distribution feeder's minimum daytime load, hot transfer standby generation, and soft loading transfer systems are typically excluded from this requirement.

Neutral reactors are required in several configurations for both rotating machines and inverters. A reactor has four ratings; reactance, continuous current rating, maximum current withstand for a maximum duration, and a voltage rating. The voltage rating for an air core reactor should exceed the withstand current times the reactance. If the voltage rating is for an iron core reactor, it must exceed the current times reactance plus a margin to ensure the reactor does not saturate under fault conditions. The lesser of 125% of current times reactance or full line-neutral voltage is suggested.

Direct connected rotating machines must comply with the traditional IEEE grounding standards. To achieve effective grounding, the IC's system Thevenin equivalent impedance must meet the two criteria given below or otherwise meet a coefficient of grounding of 80%, (see IEEE 32 and IEEE C62.92.2). Note – the effective grounding impedance is always determined with the DER separated from the Area EPS. Momentary fault withstand and continuous current ratings are always determined with the Utility and DER connected.

- The positive sequence reactance is greater than the zero-sequence resistance ($X1 > R0$).
- The zero-sequence reactance is less than or equal to three times the positive sequence reactance. The Utility requires the ratio to be between 2.0 and 2.5 ($2.0*X1 < Xo < 2.5*X1$) to limit the adverse impacts on feeder ground relay coordination.

7.9.1. Synchronous and Induction Generators

When calculating faults and effective grounding using the positive, negative, and zero sequence impedance networks, the networks should include impedances for the following: the step-up transformer, generator sub-transient reactance (Xd”), neutral grounding reactance on the step-up transformer and/or generator, secondary cable runs greater than 50 feet in length, and the grounding bank. For induction generators, the equivalent of the sub-transient reactance should be used. If the Xd” equivalent is not available, the following approximation is usually adequate:

$$X = \frac{Rated\ Voltage}{Locked\ Rotor\ Current}\,\Omega$$

The IC should submit the grounding device information for approval before it is purchased.

Many different system configurations will meet the effective grounding requirements. Transformer winding configurations are provided later in this manual and their ability to pass ground referencing through or to act as a ground source. Listed below are some guidelines and restrictions.

- A grounded-wye/grounded-wye step-up transformer is common and aligns with the Utility’s transformer standards. When this transformer arrangement is used, the DER must have an appropriately sized grounding bank, or the DER’s neutral must be adequately grounded (typically through a grounding reactor) to meet the utilities requirements for effective grounding. Utility supplied three-phase service transformers are grounded-wye/grounded-wye for four-wire systems.
- A delta (DER)/grd-wye (Utility) step-up transformer must have a reactor in its grounded-wye neutral ground bank, ($2.0*X1 < Xo < 2.5*X1$). A neutral resistor will cause high power losses and is not recommended. The Utility does not supply this configuration.
- A delta step-up transformer, with delta on the Utility’s Area EPS side, may be used. When this configuration is used, a grounding bank must be installed on the primary side of the generator step-up transformer. The grounding bank's impedance must be selected so that it meets the Utility’s effective grounding requirements above, and it must be rated to withstand the system fault current and voltage imbalance. This configuration requires a switching device to separate both the DER and ground source during system separation. Utility supplied three-phase service transformers are generally delta on the Utility side for three-wire systems.

DERs that produce power at line voltage (i.e., a step-up transformer is not needed) either must be adequately grounded (typically through a grounding reactor in the generator neutral) or have a grounding bank to meet the Utility’s effective grounding requirements. Grounding the DER is not recommended since significant DER derating due to unbalanced currents may result.

Voltage imbalance on the Area EPS may result in substantial current flowing into an IC's DER or grounding equipment. The Utility’s operating objective is to keep phase-to-phase voltage imbalance under 1% and phase-to-ground voltage imbalance under 3%. Imbalance may be higher, especially during contingency conditions. The IC's equipment must be able to withstand allowable voltage imbalances and be able to operate during an imbalance condition. A zero sequence voltage of 4% is recommended for determining the continuous imbalance rating. This rating should be adequate for contingency system configurations.

Normal system source impedance data for a given location can be obtained from the Utility. For contingencies and maintenance, field ties are temporarily used, and this can change the source impedance and fault duties as seen by IC. Normal system source impedance should be obtained before an IC purchases grounding equipment so that the equipment purchased will be appropriately rated (both for steady state and short time duty) for the given location.

7.9.2. Inverters, Double-fed Induction Generators, and Others

Inverter installations that are large, single-unit, or composite facilities should be checked for effective grounding equivalency. IEEE C62.92.2 directly applies to rotating generation and cannot be directly applied to inverters to determine ground referencing equivalency since grid connected inverters operate as a current source, not as a voltage source. Small, single-phase inverter installations are usually exempt from this requirement.

Double-fed induction generators have an equivalent short-circuit impedance that is available from the manufacturer. The equivalent combines the fault output of the stator windings and the inverter output from the rotor windings. Some double-fed generators employ a crowbar circuit on the rotor that is activated during upsets. Once the rotor is shorted, the generator acts like a standard induction generator.

The grounding requirement applies regardless of the energy source providing power to the inverter. The grounding method used needs to be compatible with the step-up transformer configuration. For three-phase installations, the phase-to-neutral over-voltages during a single line-to-ground fault must be constrained to avoid exposing the single-phase loads connected on the un-faulted phases to excessive voltage (<130% Ph-N rated voltage). The equivalent of a coefficient of grounding of 80% must be achieved, also see C62.92.4.

The following sizing method meets the grounding requirement. Transformer winding configurations and their ability to pass ground referencing through or to act as ground source is defined later in this Standard.

The grounding device or neutral reactor may be estimated according to the following criteria:

$$X_{0|DER} = 0.6 \pm 10\% \ p.u. \text{ and } \frac{X_{0|DER}}{R_{0|DER}} \geq 4 \text{ where } 1\,p.u. is\ bassed\ on\ Z_{base}\,\frac{kV^2}{MVA_{DER}}$$

DER Interface Transformer (DERIT) and Neutral Grounding Reactor (NGR)

a. the total kVA rating of the DER Facility (sum of DERITs' kVA ratings) and high side kV rating of the DERIT(s) for Grounding Transformer sizing; or
b. the kVA and high side kV rating of the DERIT for NGR sizing.

General notes include:

- DERIT kVA rating is assumed to be approximately equal to the DER capacity.
- For inverter-based interface, the "0.6" factor is a conservative approximation.
- Assume V_0=4% NGR or transformer should have a continuous current rating based on $I_{0|GB} = \frac{(4\%\, V_0)}{X_{0|DER}}$
- Momentary fault withstand must have a time rating of 5 seconds or more with 10 seconds recommended.

Many three-phase inverters will not meet the grounding requirement. Some manufacturers employ an internal high resistance between the transformer's internal wye and the neutral or ground connection, which does not qualify as ground referencing. Some manufacturers connect the inverter transformers in a delta configuration. The presence of a neutral connection on the inverter does not ensure a grounded- wye configuration. If the inverter does not provide adequate ground referencing, either a small grounding bank will be needed or grounding with a separate wye-grounded/delta transformer with neutral reactor will be needed. See later discussion of three-phase installations using single-phase inverters.

An inverter with a delta/grounded-wye matching transformer will experience imbalanced current due to distribution system voltage imbalance. This may limit the inverter output capacity or result in overcurrent shut-downs during distribution system ground faults. A solid ground connection without a suitable neutral reactor is not recommended. Use of a neutral resistor is not recommended due to the ongoing elevated losses. A neutral reactor will reduce the imbalance current, operation issues, and losses. A grounding transformer avoids these issues and is the recommended approach.

"Transformerless" inverters rated 200 kW or less may be exempted by the Utility at their sole discretion. Above 200 kW, a separate ground referencing source must be provided.

DER technologies other than those discussed above may come into use. The same principles will apply to them. The DER interconnected to the Utility's effectively grounded Area EPS must provide effective ground referencing.

7.9.3. Multi-Inverter Installations

Larger facilities are often comprised of multiple inverters, each with its own string of PV panels. For medium size installations with a secondary voltage Point of Coupling (PCC), a single ground referencing device may be installed to handle the entire facility. It can be sized in the same manner as described above. The sum of all of the included inverter AC nameplate ratings is used in the formula along with voltage at the location where the ground reference will be attached.

This same approach is used for large PV installations. The ground reference is often located at the medium voltage DER bus that connects to the PCC. The voltage to use in the formula is the medium voltage location rated voltage. The grounding method used needs to be compatible with the step-up transformer configuration.

7.9.4. Single-Phase Inverters

Three-phase DER facilities comprised of single-phase inverters must comply with NEC 705.40, 42, and 100. This applies whether there is one single-phase inverter per phase or multiple micro-inverters. Upon loss of one phase or one phase of the facility trips, the facility must cease exporting power or sense and separate the generation on all three phases. Any three-phase facility that is large enough to require the use of a grounding bank must sense and totally separate for loss of one or more phases or tripping of one or more DER phases.

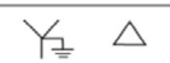
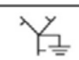
Three-phase DER facilities comprised of single-phase inverters shall be designed to produce power that is closely balanced per phase. The same considerations apply to single phase secondary service if inverters are applied hot leg to neutral. Operation that results in unbalanced power production or resulting voltage unbalance in excess of the Utility's requirements shall cease operation until a balance better than the Standard's minimum requirements can be met.

7.9.5. Ground Referencing Transformer Configurations

Three-phase DER Facilities must be ground referenced when interconnected to the four wire Area EPS. The only two types of sources that provide a ground reference includes a) a transformer with the suitable winding configuration or b) a grounded wye rotating machine. Inverters do not provide a ground source, but they may have interface transformers that can.

Transformer winding configurations that can provide a ground source also provides a source for zero sequence current. The below table identifies which transformer winding configuration provides a source for zero sequence current. The Utility's standard distribution transformer is the grounded-wye to grounded-wye. It will pass zero sequence ground reference current through to the opposite side but will not provide a zero sequence source.

If the IC is supplying the step-up transformer, there must be either a secondary ground source with a suitable transformer winding configuration or a primary ground source provided.

Transformation Primary (Pri.) ⟵ Secondary (Sec.) ⟶	Passes Zero Seq. Current?	Provides a Source for Zero Seq. Current?
	No	No
	No	No
	No	No
	Yes	No
	No	No
	No	Yes (to Sec. only)
	No	Yes (to Pri. only)
	No	No
	No	Yes (to Sec. only)
	Yes	Yes (to Pri. and Sec.)
	Yes	No
	Yes	Yes (to Pri. and Sec.)

A ground referencing transformer may be needed on a four-wire multi-grounded system where the interconnection involves the use a grounded-wye/grounded-wye step-up transformer and inverters that do not provide a ground source. When there is a single or double line-to-ground fault on the Utility's distribution system, the Utility's protective device will open and the Utility's substation's wye connection will be lost. If this occurs before the inverter shuts-down, the distribution system neutral can float off center and cause excessive Temporary OverVoltage (TOV) between one or two phases and neutral. A ground referencing transformer would provide a stabilized neutral and protection to the members'/customers' and Utility's equipment. The ground referencing transformer becomes an essential part of an entire effectively grounded system. The need for a ground referencing transformer will be determined on a case by case basis as part of the System Impact Study.

7.9.6. Ground Relays

When the IC install ground sources as discussed above, the Utility's ground overcurrent relays located at the substation and on distribution feeders will be de-sensitized during a single-line-to-ground fault when an IC's DER is operating in parallel. If the IC contributes more than 10% to a feeder line-to-ground fault, corrective measures become likely. This is rarely an issue when the generation facility uses inverters. When the IC's grounding contribution is relatively large, the Utility may require additional feeder protection equipment, at the IC's expense, to ensure a reliable and secure system configuration is maintained. The same loss of sensitivity for three-phase faults is possible especially with large rotating generation.

7.9.7. Grounding Bank Protection

When ground referencing transformers are installed to comply with the requirements, the protective relaying design and device ratings will be reviewed. The protection must be compliant with NEC Article 450.3, 450.5(A), or NESC as is applicable. The generation source must be off-line or be tripped off-line if the ground referencing transformer is unavailable or fails. If a protection scheme is AC powered, it shall be designed to minimize accidental disabling. The NEC required grounding transformer overcurrent protection should have enough time delay to coordinate with the Utility protective relaying. Protection with time delay should have a time delay that places the tripping characteristic at the grounding transformer's maximum current and withstand time rating. Protection schemes that remove ground referencing during times that the generator is off-line will be reviewed to ensure ground referencing is in service whenever the generator becomes active.

7.9.8. Non-effectively Grounded DER Connected Producers

At the sole discretion of the Utility, a DER facility under 200 kW may be other than effectively grounded if it can be shown that when the DER is islanded from the Utility and is still generating power, the kW load that will be served from the DER during the islanding condition will at all times be at least three times greater on each phase than the DER's per phase kW rating. In general, a facility under 200 kW that passes the Fast Track Screening will qualify for the ungrounded operation option. All inverters connected to spot or area networks must be effectively grounded on the secondary side.

8. Operations

8.1. Periodical Testing & Record Keeping

All interconnection-related protection and control systems shall be periodically tested and maintained, by the IC, at intervals specified by the manufacturer or system integrator and shall not exceed 10 years. Periodic test reports and a log of inspections shall be maintained by the IC and made available to the Utility upon request. The Utility 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 shall be a functional test of the protection and control systems.

The IC shall notify the Utility prior to any of the following events occurring:

- Protection functions are being adjusted after the initial commissioning process.
- Functional performance changes of the DER.
- Functional software or firmware changes are being made on the DER.

- 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.
- Protection settings are being changed after factory testing.

The Utility recommends any system that depends upon a battery for trip/protection power shall be checked and logged once per month for proper voltage.

8.2. Enter Service and Synchronization

Enter Service refers to DER starting operation following a planned or unplanned outage caused by the Area EPS or IC. Following an outage on the Local EPS, Area EPS, or other loads on the Area EPS will automatically result in the DER placing an increased power flow impact on the system. Energy storage systems should delay their recharging following these events to reduce this increased demand. All DER may also be asked to delay their starting times.

For Non-energy storage systems, the following are examples of possible restart requirements.

- The delay time for restarting of the DER after an outage may be increased.
- The DER shall stagger the restarting of inverters under normal restarting.
- Multiple transfer switches may be required for block loading DER to break up the blocks of the load transferred to the DER.

For energy storage systems, the following are some possible methods which may be required.

- The delay time for restarting of the DER after an outage may be increased.
- The charging of the energy storage system may require a predefined ramp rate.
- The discharging of the energy storage system may require a predefined ramp rate.

Refer to the energy storage systems section below for the requirements.

When entering service, the DER shall not energize the Area EPS until voltage and system frequency are within the ranges specified below.

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	≥ 59.5 Hz
	Maximum value	≤ 60.1 Hz

The DER shall parallel and synchronize with the Area EPS in accordance to IEEE 1547-2018.

8.3. Power Ramp Rates

After meeting the requirements for entering service, synchronization considerations must be made on the appropriate ramp rates of DER to prevent operational problems. As part of a system impact study, step changes in load and generation will be studied to determine the impact to system voltage. A maximum of 3% change in voltage is allowed. Should the DER cause step changes beyond this mitigation will be needed.

8.4. Power Quality

The interconnection of the IC's DER equipment with the Utility's system shall not cause any significant reduction in the quality of service being provided to other Utility customers. Certified inverters, unless they are malfunctioning or misapplied, will generally comply these requirements. Abnormal voltages, frequencies, harmonics, or interruptions must be kept within limits specified under IEEE 1547-2018 and IEEE 519. If high or low voltage complaints, voltage flicker, transient voltage complaints, and/or harmonic (voltage distortion) complaints result from operation of an IC's DER, such DER equipment may be disconnected from the Utility's system until the IC resolves the problem. The IC is responsible for the expense of keeping the DER in good working order so that the voltage, Total Harmonic Distortion (THD), Total Demand Distortion (TDD), power factor, and VAR requirements are met. IEEE 1547.2 provides additional discussion and approaches for identifying and addressing these issues.

8.5. Operating and Maintenance Agreements

Operating and maintenance requirements are documented in Interconnection and Operating Agreement. The operating and maintenance requirements are created for the benefit of both the IC and the Area EPS and shall be agreed to between the parties.

Operating and maintenance requirements may be reviewed and updated periodically to allow the operation of the DER to change to meet the needs of the IC and the Area EPS. There may also be changes required by external issues, such as changes in FERC, Transmission Owner and/or Regional Transmission Organizer recommendations or policies, which may require the updates to the operating and maintenance requirements.

The following is a list of typical items that may be included as operating and maintenance requirements.

- Operational requirements, settings, and limits for DER when the Area EPS is in a normal condition
- Operational requirements, settings, and limits when the Area EPS is in an abnormal condition due to maintenance, contingencies, or other system issues
- Permitted and disallowed energy storage system control modes
- BPS or Area EPS limitations and arrangements that could impact DER operation
- DER restoration of output or return to service settings and limitations

- Response to control or communication failures
- Performance category assignments (normal and abnormal)
- Dispatch characteristics of DER
- Notification process between IC and Area EPS
- Right of Access
- Routine maintenance requirements and definition of responsibilities
- Material modification of the DER that may impact the Area EPS

9. Control Systems

The IC may choose to limit the AC capacity of a DER system using power controls. Power controls may also be used to limit DER system export levels to the Local EPS and/or the Area EPS. There are many possible reasons for implementing power controls, including meeting specific tariff terms or to mitigate the maximum level of power which can flow on the Local EPS and/or Area EPS.

These capabilities are referred to as power control limited capacity, power control limited export, and power control limited import. These terms are discussed in the following sections and may be generally referred to as power control limiting. Power control limiting may be accomplished using a power control limiting system. An alternate option, specifically related to assurance that the DER does not export power (non-export) to the Area EPS, is to implement the limit through relaying or by sizing DER in relationship to the size of the Local EPS load. The use and method for power control limiting shall require approval from the Utility.

9.1. Power Control System Requirements

If a power control system is used, it must meet the following requirements:

- Control system must monitor import and export power at the point of common coupling with the Area EPS.
- Shall control energy production from the DER by tripping or curtailing energy production within 2 seconds of receiving a signal to do so.
- Shall self-monitor the control system, such that failure of the control system to control or monitor will result in the tripping of the DER or separation from the Area EPS. This includes loss of control system power.
- The power to the control system must be battery backed up.
- Access to configuration and settings should be restricted to authorized and qualified personnel by means of password protection.

9.2. Common Control Modes

An operating mode means the mode of DER operational characteristics that determines the performance during normal and abnormal conditions. Several operating modes are most typical with power control systems. Most services provided by a power control system can be categorized into one of three common operating modes, although each service will have unique settings depending on the specific goal of the power control system. In the Interconnection Application and on the one-line diagram, one of these three operating modes shall be listed. If none of the below apply, provide a description of the operating mode:

- Limited Export at the PCC- The power control system controls the amount of real power that is exchanged across the point of common coupling with the Area EPS.
- Limited DER Output Capacity- The power control system controls the amount of real power that the DER is capable of outputting at the point of connection, behind the IC's side of the point of common coupling with the Area EPS.
- Import Only - The power control system prevents the DER from exporting real power across the point of common coupling with the Area EPS. This restriction may be placed on a single DER within a system of multiple DER, such as only on an energy storage system while allowing PV to export, or may be placed on all DER behind a single point of common coupling with the Area EPS.

9.3. Documentation

When the DER implements the use of a power control system, it is generally to prevent export or limit export of a DER, control charging of an energy storage system, or limit the total DER capacity. The operating modes and control modes that the power control system may use are not typically certified to a national standard, and therefore need to be reviewed by the Utility to ensure compliance with applicable requirements of the Area EPS and/or BPS. When a review is required, there is often additional information that the IC needs to provide to the Utility. The following documentation shall be submitted as an attachment with the Interconnection Application when a power control system is being proposed:

a. Manufacturer and model of the power control system, or of the components that make up the power control system.
b. User manual of the power control system.
c. A control schematic of the power control system, showing instrumentation, sensors, breakers, and DER.
d. A listing of the operating modes and services that will be available in the power control system.
e. A listing of the operating modes and services that will be enabled.
f. A description of the operating modes, services, and any specific settings that are enabled, and how the hardware/software present in the design is used to accomplish the goals of each mode being used.

g. A description of how operating modes and services not being enabled are locked down to prevent unintentional enabling.
h. State the enabled operating mode, on the one-line diagram and interconnection application.
i. Additional information that may be requested by the Utility to clarify operation of the power control system.

9.4. Inadvertent Export

Inadvertent export is the unscheduled and uncompensated flow of real power, through the point of common coupling and back into the Area EPS. Inadvertent export may occur during sudden changes in electrical demand on the Local EPS and must be quickly resolved through the automatic adjustment of the DER output through the direction of the DERs power control system.

Inadvertent export, if it is large enough, could cause tripping of protective devices and a resulting power outage. For DER systems which are designed as non-exporting, the Area EPS has not been constructed to support the reverse flow of energy and may not be able to support it.

If reverse power flow is possible, collaborate with local Transmission Owner on impact assessments that may be needed.

10. Interoperability

As DER penetration rises, there will be an increasing need to provide the Utility with ongoing indication of the DER production. There will be evolving requirements as the penetration rises in both facility size and functionality. Work is in progress for smart inverters and advanced interconnection and communication standards to facilitate this evolution. At high penetrations of DER, there will be a growing need to also provide control instructions to the inverters such as shifting to a different voltage control mode. The following is an overview of the requirements at the time this manual is published. The IC should verify the requirements as part of the application process.

10.1. Monitoring and Control Requirements

10.1.1. 20 kW to 200 kW

The Utility may require the ability to remotely monitor the output of small to medium size installations. This information is needed to quickly address Area EPS and BPS constraints and contingency conditions, as required by NERC reliability standards. This does not apply to facilities that qualify for closed load transition status. Monitoring of small DER may be done through an aggregator or Utility provided neighborhood collector.

The information required will vary by DER location and size, but all will include real and reactive power, voltage, and unit connection status. Whenever the IC is located in an Area EPS or BPS constrained region, generates power in excess of the Area EPS load, or is in an area with a high penetration of DER, this monitoring is more likely to be needed.

The IC is expected to provide suitable space or enclosure for the installation of the monitoring and telemetry equipment. The cost of IC's site terminal equipment, any added metering, interface security device when needed, and ongoing communication channel costs to the designated Utility point of receipt is the IC's responsibility when telemetry is a condition of interconnection.

10.1.2. 200 kW to 1 MW

As DER penetration levels increase, the Utility will require the ability to remotely monitor the output of intermediate size installations as distribution control, safety, and power quality will require greater DER monitoring in addition to Utility provided feeder monitoring. This information is needed to quickly address Area EPS and BPS constraints and contingency conditions, as required by NERC reliability standards, which must be addressed quickly. This may not apply to facilities that qualify for closed load transition status.

The information required will vary by DER location and size, but all will include real and reactive power, voltage, energy production, and unit connection status at or faster than the designated scan intervals. Whenever the IC is located in an Area EPS or BPS constrained region, generates power in excess of the Area EPS load, or is in an area with a high penetration of DER, this monitoring will be needed.
The IC is expected to provide suitable space or enclosure for the installation of the monitoring and telemetry equipment. The cost of IC's site terminal equipment, any added metering, interface security device when needed, and ongoing communication channel costs to the designated utility point of receipt is the IC's responsibility when telemetry is a condition of interconnection.

10.1.3. 1 MW and Greater

DER facilities 1 MW-AC and greater may be required to provide and pay for telemetry as part of the required system modifications per state and Utility requirements. This includes the IC's site-end terminal equipment, any added metering, and interface security device when needed, and ongoing secure communication channel costs to the designated Utility point of receipt. This does not apply to facilities that qualify for closed or soft load transition status.

The information required may vary by DER location and size but all will include near real time active and reactive power, point of delivery voltage, connection status, and integrated energy. Near real time means samples every 5 seconds or less with less than one second delivery delay. Whenever the IC is located in an Area EPS or BPS constrained region, generates power far in excess of the Area EPS load, or is in an area with a high penetration of DER, more stringent monitoring and control may be needed. If the IC is located on a high penetration DER circuit, especially if it is capacity constrained, is likely to be required to have more extensive control.

Additional information may be required, either initially or later, such as ambient, wind speed, or solar intensity.

The Utility may require the ability to remotely disconnect or curtail the DER for installations 1 MW and larger. For some installations, a remote ability to change control modes, such as power factor setting, may be required. This will be determined during the facility review. This control is needed to quickly address Area EPS and BPS constraints and contingency conditions, as required by NERC reliability standards, which must be addressed quickly. If the IC does not provide a suitable device to be controlled, the Utility will install a suitable device on the feeder, at the IC's expense, to provide the control. The control of this device will be exercised in a non-discriminatory manner in compliance with the NERC standards. Interface with the inverters or the site controller is preferred as it provides more, and often less disruptive options.

The Utility either will provide the specifications for the equipment or the needed equipment, at cost, to the IC for the IC's site. The Utility will provide the equipment at the Utility's designated delivery location at Utility cost.

The IC is expected to provide suitable floor space or an enclosure in a suitable location.

The IC is to provide the secure communications channel to the Utility's dispatch facility or other designated location to provide the required communication path between the DER facility and the Utility. The Utility will define the needed minimum security, through-put, and latency requirements needed. This will be determined in the facility review.

Maintenance costs for telemetry related equipment at the IC's site is the responsibility of the IC.

10.2. Transfer Trip Considerations

Considerations for transfer trip are discussed in an earlier Section of this manual. The customer must work with the Utility to understand the design requirements for these systems.

10.3. Security Requirements

10.3.1. Physical Security

It is the responsibility of the IC to maintain physical security for equipment, communication, and control interfaces at the DER site. Front panel or local access to any protection, control or communication interfaces shall be password protected to allow only qualified personnel access.

10.3.2. Network Security

It is the IC's responsibility to ensure cyber security of any DER equipment or communication interfaces provided by the IC. The IC must assure there are now cyber connections with the internet and DER communication systems connected to the Utility. The communication link between any piece of equipment and the Utility shall be a direct link and not a shared communication channel with any other communication.

11. Energy Storage Systems

Various types of Energy Storage Systems (ESS) may be considered that connect in parallel to the Area EPS. Battery storage is common for DER applications where the primary benefit enables DER sources to be dispatched/adjusted upon request behind the meter. In these cases, the ESS is charged by the DG system to be available later to dispatch the stored energy when the DER facility is not generating. Customers may apply battery storage energy when the DER facility is not generating. Customers may apply battery storage where there is no DER facility to take electricity from the Area EPS , store the electricity, and then use the behind the meter stored electricity at a time when the DG system isn't generating.

ESS has the potential for significant effects on the load flow of the Area EPS and the overall dispatch characteristics of the system. An ESS can be complemented by "smart inverter" technology at the point of common coupling, which could also affect the Area EPS. Under such circumstances, it is critical to understand the operating characteristics of the ESS, including import and export times, as well as equipment power ratings and capabilities. Additional information may be required at the time of application for interconnection such as:

- Method of ESS connection whether:
  - ESS directly connected to the Area EPS
  - DER and ESS DC coupled
  - DER and ESS AC coupled
  - ESS on Utility line side of service point and revenue meter
  - ESS on load side of service point and Utility revenue meter with the premises load
- Sequence of operation for the charging and discharging capabilities of the ESS and the maximum ramp rate in watts/seconds.
- If the ESS and DER can generate power at the same time or if the maximum allowed generation is the output of the DER.
- Non-UL 1741 listed inverters will require a utility grade intertie relay with the appropriate IEEE 1547 functions, settings, and islanding protection according to the Utility's requirements.
- Service configuration and revenue metering provisions shall meet the Utility's requirements.

12. Microgrids

Various types of microgrids may be considered that connect in parallel to the Area EPS. Microgrids may be particularly appropriate to address resiliency and reliability. The Utility's position is that when a community microgrid serves multiple customers (in contrast to a facility or campus-style microgrid serving a single customer such as a university or hospital), including residential customers, and operates with the surrounding electric distribution infrastructure, the Utility is in the best position to own and properly operate electric distribution facilities within the community microgrid for the public interest in terms of safety, reliability, and resiliency.

The Utility emphasizes the importance of the compliance of all microgrids with the safety requirements of applicable codes. The Utility electric distribution facilities connecting participants and users in community microgrids are delivered systems governed by the National Electrical Safety Code® (NESC) as adopted by the local jurisdictional authority. The individual customers connected to the community microgrid through the Utility's electric distribution facilities have premises wiring systems that are governed by both the NEC, as adopted by the local jurisdictional authority, and the Utility's own electric service rules for safety of user from the hazards of electricity.

The Utility must be able to control the isolation of a community microgrid at each point of common coupling with the Area EPS if the Utility is to be held accountable for the safety and reliability of service within such a microgrid. This isolation can be achieved by visible break disconnect switches, interrupting devices or a combination thereof which can be manually or remotely operated by the Utility. DERs may be permitted to automatically trip a microgrid point of common coupling isolation device in order to island the community microgrid; however, they should be blocked from closing such a device until authorized to do so by the Utility's control center. The control scheme that will disconnect and reconnect the community microgrid from the Area EPS must be permitted will each have their own complexities. As such, each community microgrid will require that specific protocols be developed to ensure that customer safety and the overall Area EPS safety and reliability are not in any way compromised.

Common microgrid DER interconnection equipment, protective system and microgrid controllers at the point of common coupling with the Area EPS are to be designed and operated according to the Utility's requirements and specifications as well as to applicable codes and industrial standards. These assets may be owned and operated by IC or third parties. Individual DER facilities interconnections for connecting to the Area EPS in a microgrid shall comply with all applicable requirements identified within the manual.

13. Metering Requirements

The Utility will own, operate, and maintain all billing metering installations.

Typically, secondary metering will be used when the Utility owns the interconnecting transformer and primary metering will be used when the IC owns the interconnecting transformer. In some cases, the Utility may agree to meter on the secondary side of an IC owned transformer. In this case, the IC must provide transformer test reports, and any other related conductor or bus information so that the Utility can calculate and apply a "loss compensation" through the transformer.

The IC shall always provide the Utility access to the premises to install, maintain, and remove metering equipment. The IC may, at its option, have a representative witness work on the metering equipment by the Utility.

The metering installation shall be constructed in accordance with the practices, which normally apply to the construction of metering installations for residential, commercial, or industrial customers. For facilities with multiple DER installations, metering for each DER may be required. When practical, multiple DER installations may be metered at a common point provided the metering quantity represents only the gross DER output.

The Utility will supply the IC all required metering equipment and specifications and requirements relating to the location, construction, and access of the metering installation. The Utility will also provide consultations pertaining to the meter installation requirements as required.

The responsibility for installation of the equipment is shared between the Utility and the IC. The IC may be required to install some of the metering equipment on its side of the point of common coupling., including instrument transformers, cabinets, conduits, and mounting surface. All metering equipment must meet the Utility's specifications and requirements.

The Utility or its subcontractor will install the meter and communication connections.

Submetering associated with load control and special rate programs may not be permissible with certain DER applications. It is the responsibility of the IC to verify if the Utility's load control and special rate policies allow DER installations. If these policies do not, it may be the IC's responsibility to remove and rewire existing submetering.

14. Signage and Labeling

All signage and Labeling shall meet the applicable NEC requirements including:

- NEC 110.21 (B)
- NEC 690.13 (B)
- 705.10

14.1. Utility AC Disconnect

The Utility AC disconnect shall be labeled as "Utility AC Disconnect".

If a single Utility AC Disconnect cannot be used to disconnect all DERs, all Utility AC Disconnects shall include numerical identification such as "Utility AC Disconnect 1 of 2" or similar. The number of disconnects required to be operated to isolate the DER from the Area EPS shall be clear.

14.2. Main Meter

A sign at the main service meter shall indicate that DER is present. Each type of DER present shall be listed (i.e. PV, Wind, Energy Storage System, Gas Generator). The sign shall provide clear direction to the distance and location of all DER Utility AC Disconnects that are required to be within 10 feet and within clear line-of-sight or the main service meter unless given a written exemption from the Utility. A map shall include outline of all structures in the area and compass arrow for orientation.

14.3. Production Meter

The production meter shall be labeled as “Production Meter”. When multiple production meters exist, each production meter shall be labeled in a manner that identifies which DER is being metered. Ownership of Production Meter shall be indicated.

15. Test and Verification Requirements

To assure the safety and reliability of the EPS once the DER has been interconnected, testing and commissioning requirements and procedures set forth in this document must be followed.

15.1. UL 1741 Type Testing.

The interconnection process allows for certification of DER equipment. This certification is recognized as UL 1741 for inverter-based DER. UL 1741 certification only applies to the inverter itself, while IEEE 1547 is applicable to the complete DER installation. Aggregated inverters, supplemental devices, such as ground reference banks, or additional protective relays may cause the system to be non-compliant with IEEE 1547. Additional review must be conducted to assure the complete systems compliance with IEEE 1547. Additional protective relays or equipment settings changes may be required to achieve compliance. For more complex systems a professional engineer may need to be consulted to evaluate compliance with IEEE 1547. Using UL 1741 certified inverters will reduce the scope of commissioning testing.

For inverter-based systems, non-UL 1741 certified inverters are not eligible for interconnection with the Area EPS. Three-phase systems made up of single-phase inverters not certified for use in a three-phase configuration are also not eligible for interconnection with the Area EPS.

The use of UL 1741 certified inverters does not automatically qualify the IC to be interconnected to the Area EPS. Non-UL 1741 certified DER still must meet the requirements of IEEE 1547 and this manual.

15.2. Certified Test Reports

A certified test report is a document that has been stamped as correct and complete by a Professional Engineer licensed to practice in the State of the DER installation. For units less than 200 kW, certification by a testing professional, such as NETA (InterNational Electrical Testing Association) or equivalent, will be accepted. Other testing documentation may be accepted at the sole discretion of the Utility.

15.3. Witness Testing

IC is to demonstrate the correct operation and functionality of the interface protective devices. Only a simple, operation demonstration may be needed for small, certified interconnection packages. Some additional demonstration for larger or multiple certified packages may be required.

For larger facilities, especially where non-certified interface equipment is used, Customers must provide qualified electricians, technicians, and operators, as needed, to perform the demonstrations. The Customer must supply all personal protective equipment (PPE) required and designate any procedures necessary to ensure that appropriate safety precautions are taken while working near energized equipment. For large, complex facilities, the Utility may require a written commissioning plan prior to the testing date.

The scheduling of this demonstration should be coordinated to comply with the time frames specified by the Utility. The Utility may need to schedule multiple parties to participate in the witnessing. Where the facilities are large compared to the feeder capacity, special arrangements such as temporary field switching may be needed. Coordination with feeder maintenance and construction may be required, which may delay commissioning completion. Based on the size and type of DER at the site, the Utility may require only a design and relay setting review and not a site visit. This is to be determined by the Utility.

15.4. Equipment Commissioning Tests (Pre-Energization)

- Instrument Transformer Tests – CTs (Current Transformers) and VTs (Voltage Transformers) must be checked to verify proper wiring, polarity, and ratios. The installation should be checked against the design drawings approved by the Utility. CT's should be visually inspected to make sure shorting screws have been removed where required.
- Breaker and Switch Tests – Verify any interlocks between breakers and switches are functioning as designed. Verify any remote/local control or enable/disable control circuits or logic are functioning as designed. These verifications should be done by functional testing
- Trip Checks – Protective relay control circuits shall be functionally tested to ensure correct operation. The complete system should be tested by means of current or voltage injection to trigger an expected relay operation. Verify the relay operation trips the correct breaker, lockout or other protective or control element. The trip circuits shall be functionally verified from the correct relay operation to the breaker tripping. For inverters, UL1741 certification is adequate for the internal inverter functions.
- Remote Control and Monitoring – All remote control and monitoring SCADA points shall be verified operational. Analog points that are not able to be verified prior to energization may be verified at energization.
- Grounding – Shall be verified to ensure that it complies with the grounding requirements identified earlier in this manual, in addition to the NESC and NEC.
- Phase Rotation – The interconnection customer should work with the Utility to ensure proper phase rotation of the DER and wiring. UL 1741 certified inverters that do not

intentionally island are not required to perform this test.

- Synchronizing Test – A pre-energization functional test demonstrating the DER paralleling-device will not allow closer if frequency, voltage, and phase angle are outside of the ranges required in IEEE-1547. For UL 1741 certified inverters, this test may not be required unless the inverter creates voltages for micro-grid or intentional Island operation.

15.5. Commissioning Tests (Energization)

The following tests will proceed once the DER has completed the pre-energization testing and the results have been approved by the Area EPS. As-built drawings, inverter settings, relay settings, and other calculations and information shall be provided to the Utility prior to the scheduled witness test. All energized commissioning tests shall be based on written test procedures established by the Utility.

The following steps will be a minimum requirement:

- Verification of site Access – The site, and associated equipment, must have 24/7 unescorted access available to the Utility. This access should be drivable and keyless.
- As-built Verification – Verification that the installation matches the approved as-built one-line diagrams.
- Labeling Verification – The labeling must be meet the requirements of this manual.
- Remote Control and Monitoring – Any testing of the SCADA systems that could not be done prior to energization should be done at this stage.
- Anti-Islanding Test – Compliance with IEEE-1547 should be verified with the following steps. IEEE 1547.1 shall be referenced for evaluation of acceptable testing procedures.

    a) The DER system shall be started and connected in parallel with the Area EPS source.
    b) The Area EPS source shall be removed by opening a switch, breaker etc.
    c) The DER system shall either separate with the local load or stop generating within 2 seconds.
    d) The device that was opened to remove the Area EPS source shall be closed and the DER system shall not re-parallel with the Area EPS for at least 5 minutes or per a mutually agreed upon enter service time.

15.6. Final System Sign-off

To ensure the safety of the public, all DER systems greater than 200 kW, and all DER systems of any size which are not UL 1741 certified, shall be certified as ready to operate by a Professional Engineer registered in the same state as the DER installation, prior to the installation being considered ready for commercial use. This certification shall be provided with the certified test report submitted to the Utility.

15.7. Periodic Testing and Record Keeping

Refer to the Operations Section of this manual.

16. Sample Documents

Sample one-line diagrams are attached at the end of this manual. Samples include:

- Figure 1 – Certified inverter interconnection packages < 20 kW
- Figure 2 – Non-certified interconnections < 20 kW
- Figure 3 – Non-certified interconnections between 20 kW and < 200 kW
- Figure 4 –Certified interconnection packages between 20 kW and < 200 kW
- Figure 5 – Non-certified interconnections between 200 kW and < 1 MW
- Figure 6 –Certified interconnection packages between 200 kW and < 1 MW
- Figure 7 – Interconnections 1 MW and greater

17. Certified Facility

17.1. Certification Codes and Standards

The following list of references codes and standards can be used to develop the definition of a certified facility. When the stated version of the following standards is superseded by an approved revision then that revision shall apply.

IEEE 1547-2003 IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems

IEEE 1547a-2014 IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems –Amendment 1

IEEE 1547.1-2005 IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems

IEEE 1547.1a-2015 (Amendment to IEEE Std 1547.1 –2005) IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems – Amendment 1

UL 1741 Inverters, Converters, Controllers, and Interconnection System Equipment for Use in Distributed Energy Resources (2010)

NFPA 70 (2017), National Electrical Code

IEEE Std C37.90.1(2012) (Revision of IEEE Std C37.90.1-2002), IEEE Standard for Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems Associated with Electric Power Apparatus

IEEE Std C37.90.2 (2004) (Revision of IEEE Std C37.90.2-1995), IEEE Standard for Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers

IEEE Std C37.108-20021989 (Revision of C37.108-19892002), IEEE Guide for the Protection of Network Transformers

IEEE Std C57.12.44-2014 (Revision of IEEE Std C57.12.44-2005), IEEE Standard Requirements for Secondary Network Protectors

IEEE Std C62.41.2-2002, IEEE Recommended Practice on Characterization of Surges in Low-Voltage (1000V and Less) AC Power Circuits

IEEE Std C62.41.2-2002_Cor 1-2012 (Corrigendum to IEEE Std C62.41.2-2002) -IEEE Recommended Practice on Characterization of Surges in Low-Voltage (1000 V and Less) AC Power Circuits Corrigendum 1: Deletion of Table A.2 and Associated Text

IEEE Std C62.45-2002 (Revision of IEEE Std C62.45-1992) -IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000 V and less) AC Power Circuits

ANSI C84.1-(2016) Electric Power Systems and Equipment –Voltage Ratings (60 Hertz)IEEE Standards Dictionary Online, [Online]NEMA MG 1-2016, Motors and Generators

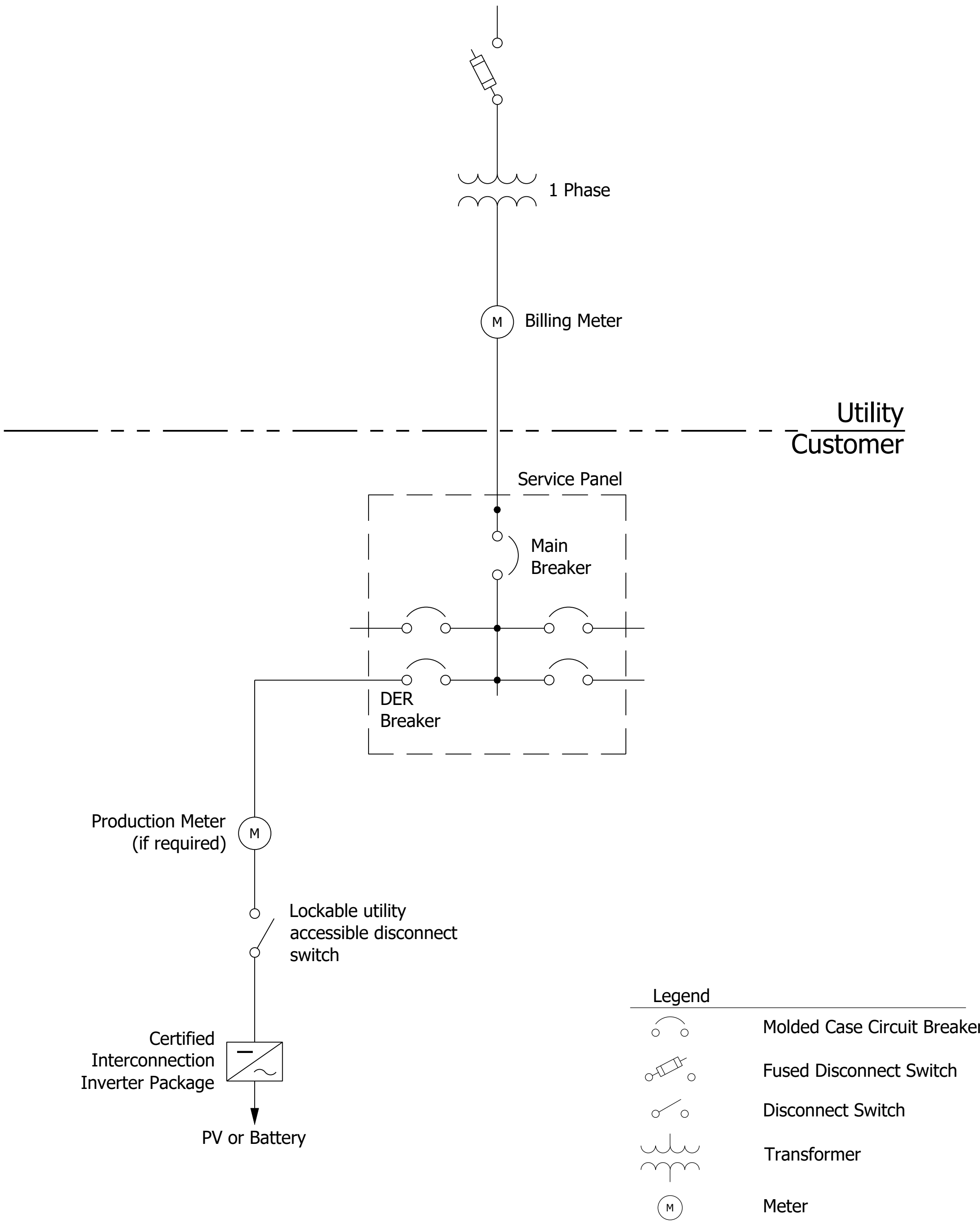
IEEE Std 519-2014, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems.

17.2. Certification of Distributed Energy Resource Equipment

1. DER equipment proposed for use in an interconnection system shall be considered certified for interconnected operation if: 1) it has been tested in accordance with industry standards for continuous utility interactive operation in compliance with the appropriate codes and standards referenced below by any Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration to test and certify interconnection equipment pursuant to the relevant codes and standards, 2) it has been labeled and is publicly listed by such NRTL at the time of the interconnection application, and 3) such NRTL makes readily available for verification all test standards and procedures it utilized in performing such equipment certification, and, with consumer approval, the test data itself. The NRTL may make such information available on its website and by encouraging such information to be included in the manufacturer's literature accompanying the equipment.
2. The Interconnection Customer must verify that the assembly and use of the equipment falls within the use or uses for which the equipment was tested, labeled, and listed by the NRTL.
3. Certified equipment shall not require further type-test review, testing, or additional equipment to meet the requirements of this interconnection procedure; however, nothing herein shall preclude the need for a DER Design Evaluation or an on-site commissioning test by the parties to the interconnection.
4. If the certified equipment package includes only interface components (switchgear,

inverters, or other interface devices), then an Interconnection Customer must show that the generator or other electric source being utilized with the equipment package is compatible with the equipment package and is consistent with the testing and listing specified for this type of interconnection equipment.

5. Provided the generator or electric source, when combined with the equipment package, is within the range of capabilities for which it was tested by the NRTL, and does not violate the interface components' labeling and listing performed by the NRTL, no further type-test review, testing or additional equipment on the customer side of the Point of Common Coupling shall be required to be considered certified for the purposes of this interconnection procedure; however, nothing herein shall preclude the need for a DER Design Evaluation or an on-site commissioning test by the parties to the interconnection.
6. An equipment package does not include equipment provided by the Area EPS.



Power System Engineering, Inc.

Sample One-Line Diagram for Certified Inverter Package Installations

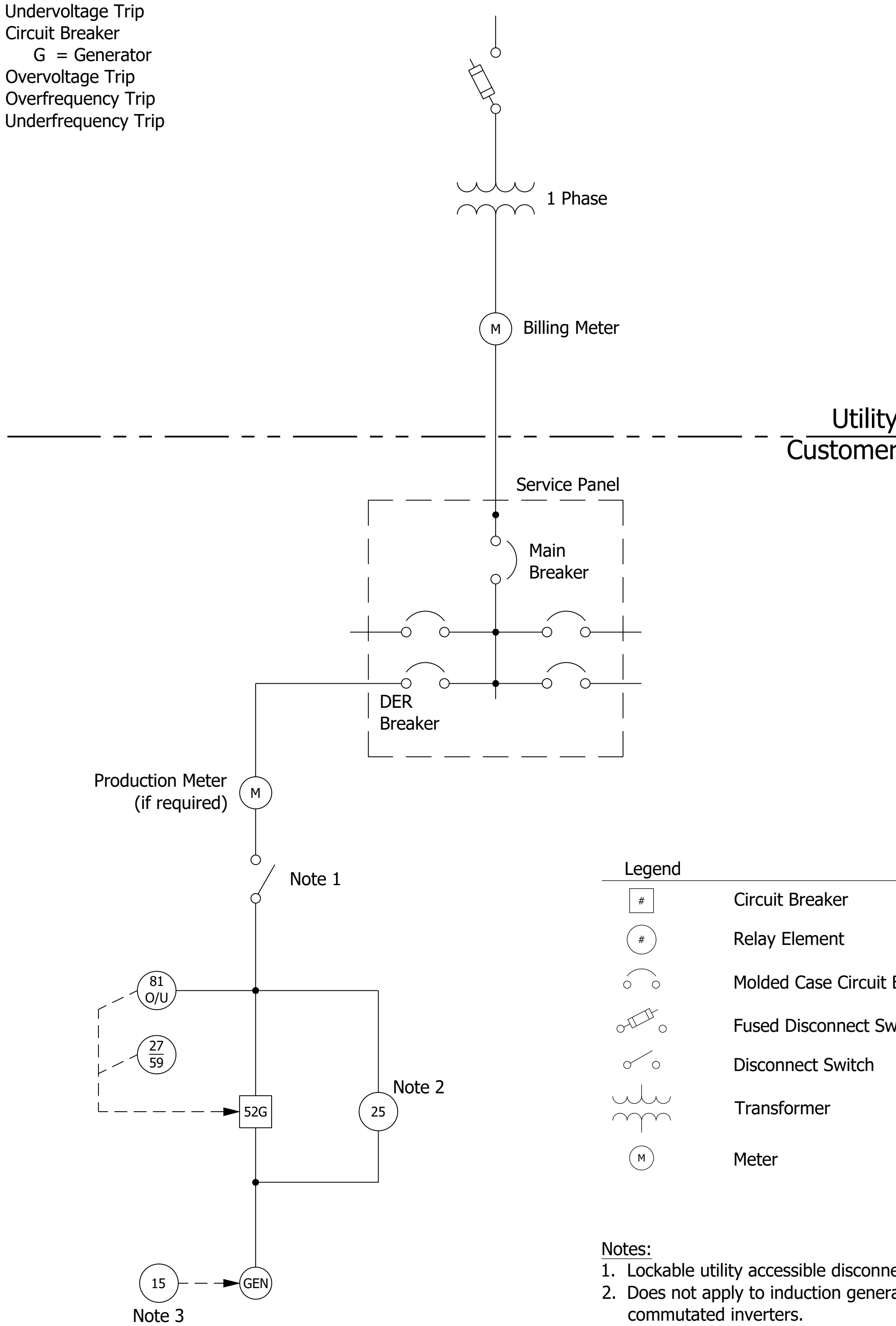
Less than 20kW

(Figure 1)

DATE: 06/10/2022	DRAWN BY: KI	APPROVED BY: DFJ	SCALE: None

Relay Elements

15	Speed Matching
25	Synchronizer
27	Undervoltage Trip
52	Circuit Breaker
	G = Generator
59	Overvoltage Trip
81-O	Overfrequency Trip
81-U	Underfrequency Trip



Legend

- Circuit Breaker
- Relay Element
- Molded Case Circuit Breaker
- Fused Disconnect Switch
- Disconnect Switch
- Transformer
- Meter

Notes:
1. Lockable utility accessible disconnect switch.
2. Does not apply to induction generators or line commutated inverters.
3. Applies to induction generators only.
4. Relays do not have to be individual. Functions may be incorporated in the interface protection package or as part of an inverter.
5. All relays shall be utility grade.

PSE
Power System Engineering, Inc.

Sample One-Line Diagram for DER Interconnection

Less than 20kW

(Figure 2)

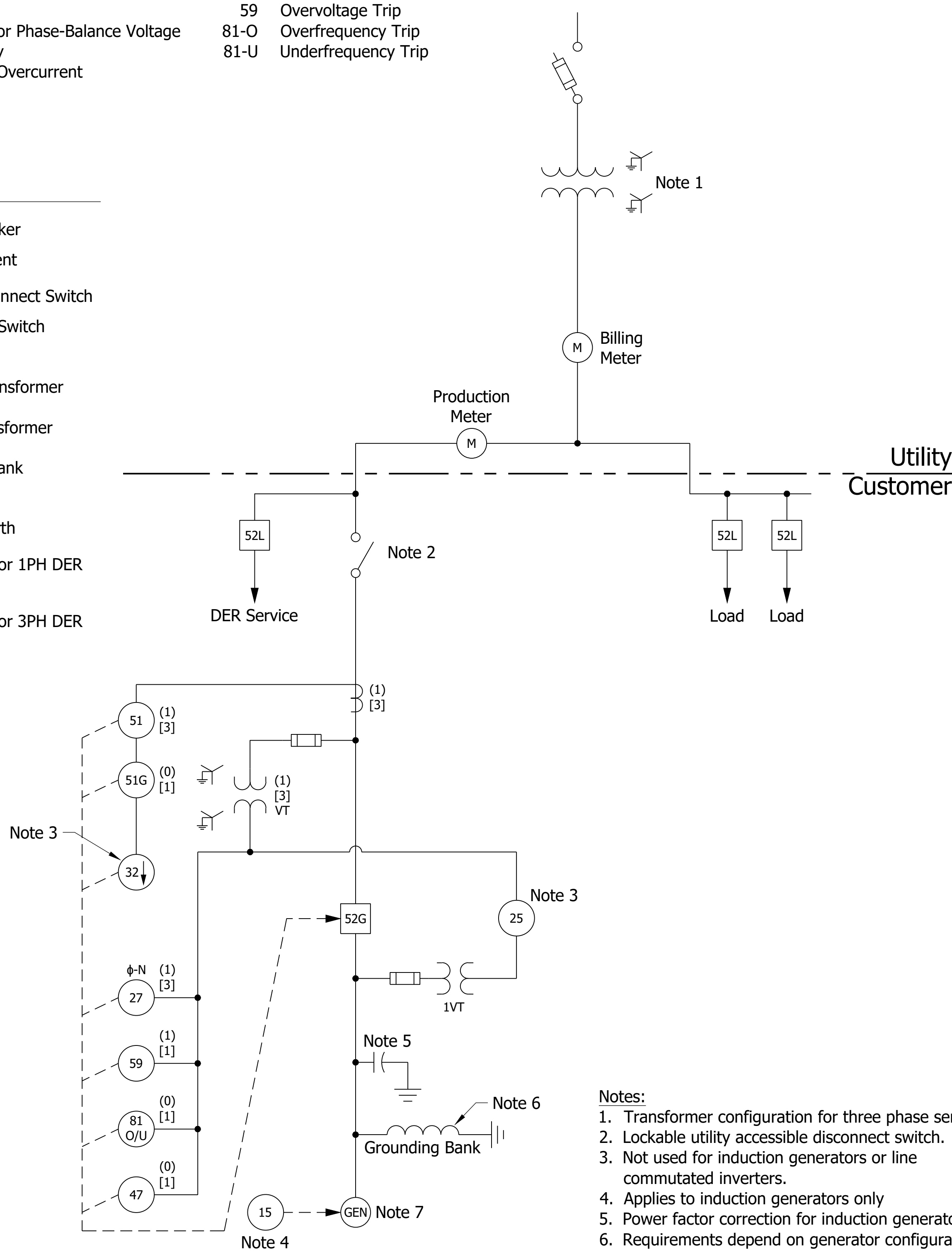
DATE: 06/10/2022	DRAWN BY: KI	APPROVED BY: DFJ	SCALE: None

Relay Elements

15	Speed Matching	52	Circuit Breaker
25	Synchronizer		L = Load
27	Undervoltage Trip		G = Generator
32	Reverse Power	59	Overvoltage Trip
47	Phase-Sequence or Phase-Balance Voltage	81-O	Overfrequency Trip
51	Overcurrent Relay	81-U	Underfrequency Trip
51G	Residual Ground Overcurrent		

Legend

- Circuit Breaker
- Relay Element
- Fused Disconnect Switch
- Disconnect Switch
- Fuse
- Voltage Transformer
- Power Transformer
- Capacitor Bank
- Meter
- Ground, earth
- (#) Quantities for 1PH DER applications
- [#] Quantities for 3PH DER applications



Notes:

1. Transformer configuration for three phase service.
2. Lockable utility accessible disconnect switch.
3. Not used for induction generators or line commutated inverters.
4. Applies to induction generators only
5. Power factor correction for induction generators.
6. Requirements depend on generator configuration.
7. 25kW AC maximum output for single phase applications.
8. Relays do not have to be individual. Functions may be incorporated in the interface protection package or as part of an inverter.

PSE

Power System Engineering, Inc.

Sample One-Line Diagram for DER Interconnection

20kW to less than 200kW

(Figure 3)

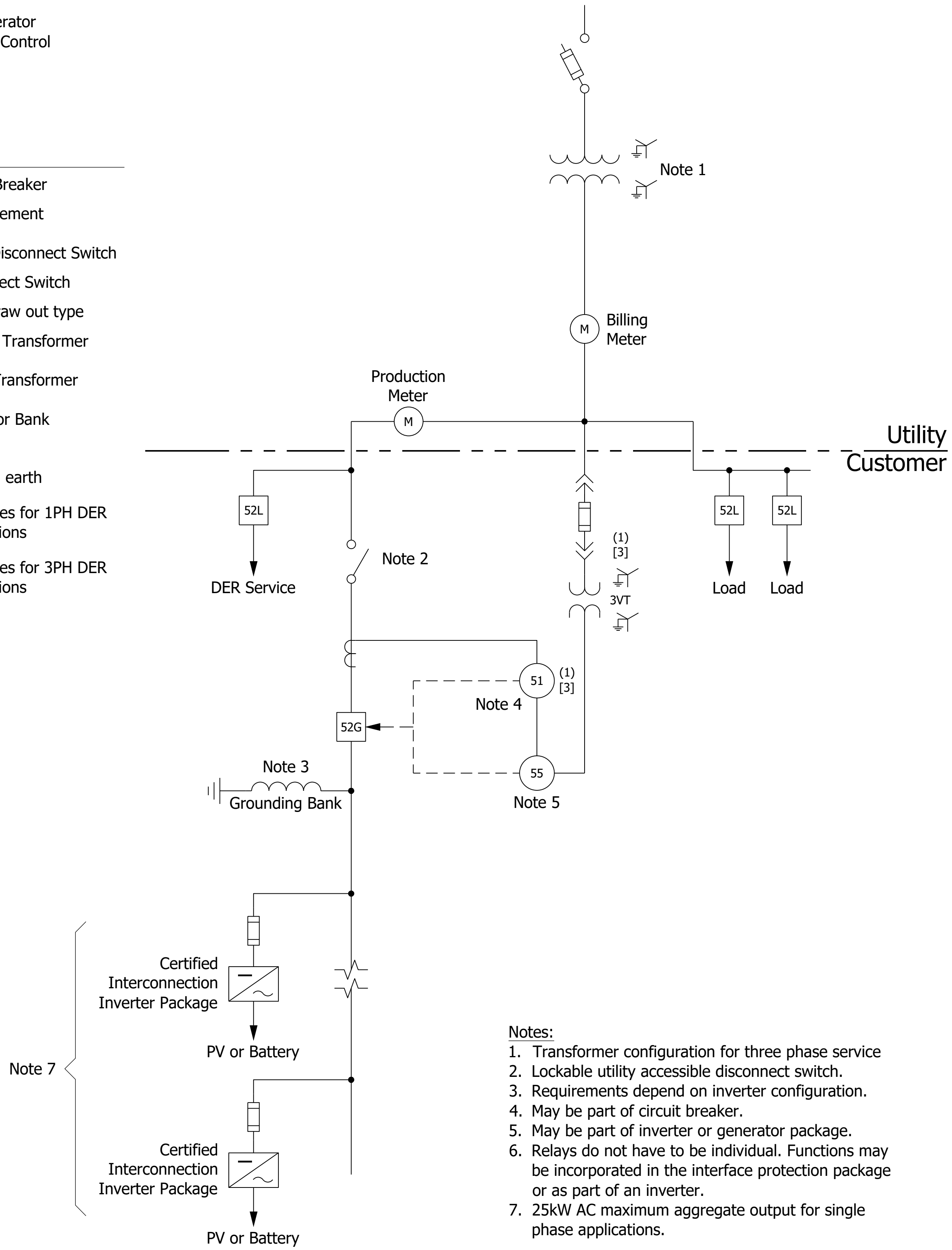
DATE: 06/10/2022	DRAWN BY: KI	APPROVED BY: DFJ	SCALE: None

Relay Elements

25	Synchronizer
32	Reverse Power
51	Overcurrent Relay
52	Circuit Breaker
	L = Load
	G = Generator
55	Power Factor Control

Legend

#	Circuit Breaker
#	Relay Element
	Fused Disconnect Switch
	Disconnect Switch
	Fuse, draw out type
	Voltage Transformer
	Power Transformer
	Capacitor Bank
M	Meter
	Ground, earth
(#)	Quantities for 1PH DER applications
[#]	Quantities for 3PH DER applications



Notes:
1. Transformer configuration for three phase service
2. Lockable utility accessible disconnect switch.
3. Requirements depend on inverter configuration.
4. May be part of circuit breaker.
5. May be part of inverter or generator package.
6. Relays do not have to be individual. Functions may be incorporated in the interface protection package or as part of an inverter.
7. 25kW AC maximum aggregate output for single phase applications.

PSE
Power System Engineering, Inc.

Sample One-Line Diagram for Certified Inverter Package Installations

20kW to less than 200kW

(Figure 4)

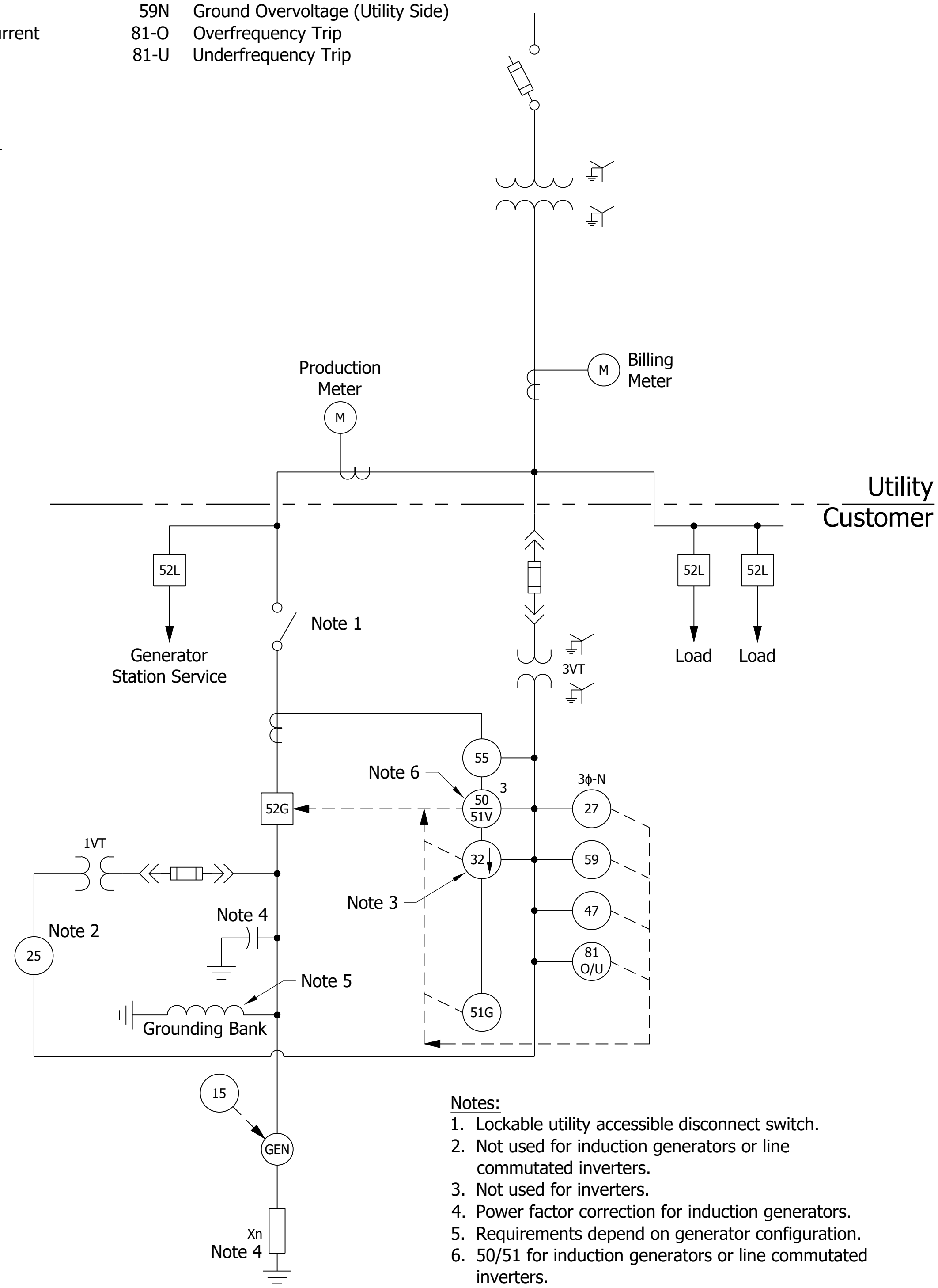
DATE: 06/10/2022	DRAWN BY: KI	APPROVED BY: DFJ	SCALE: None

Relay Elements

15	Speed Matching for Induction Gen
25	Synchronizer
27	Undervoltage Trip
32	Reverse Power
47	Phase-Sequence or Phase-Balance Voltage
50/51V	Voltage Controlled Time Overcurrent with Instantaneous, 1/Phase
51G	Residual (Ground) Time Overcurrent
52	Circuit Breaker L = Load T = Transformer G = Generator
55	Power Factor/VAR Controller
59	Overvoltage Trip
59N	Ground Overvoltage (Utility Side)
81-O	Overfrequency Trip
81-U	Underfrequency Trip

Legend

Xn	Neutral Reactor
#	Circuit Breaker
#	Relay Element
	Fused Disconnect Switch
	Disconnect Switch
	Fuse, draw out type
	Potential Transformer
	Transformer
	Capacitor Bank
M	Meter
	Ground, earth



Notes:

1. Lockable utility accessible disconnect switch.
2. Not used for induction generators or line commutated inverters.
3. Not used for inverters.
4. Power factor correction for induction generators.
5. Requirements depend on generator configuration.
6. 50/51 for induction generators or line commutated inverters.
7. Relays do not have to be individual. Functions may be incorporated in the interface protection package or as part of an inverter.
8. All relays shall be utility grade.

Power System Engineering, Inc.

Sample One-Line Diagram for DER Interconnection

200kW to less than 1MW

(Figure 5)

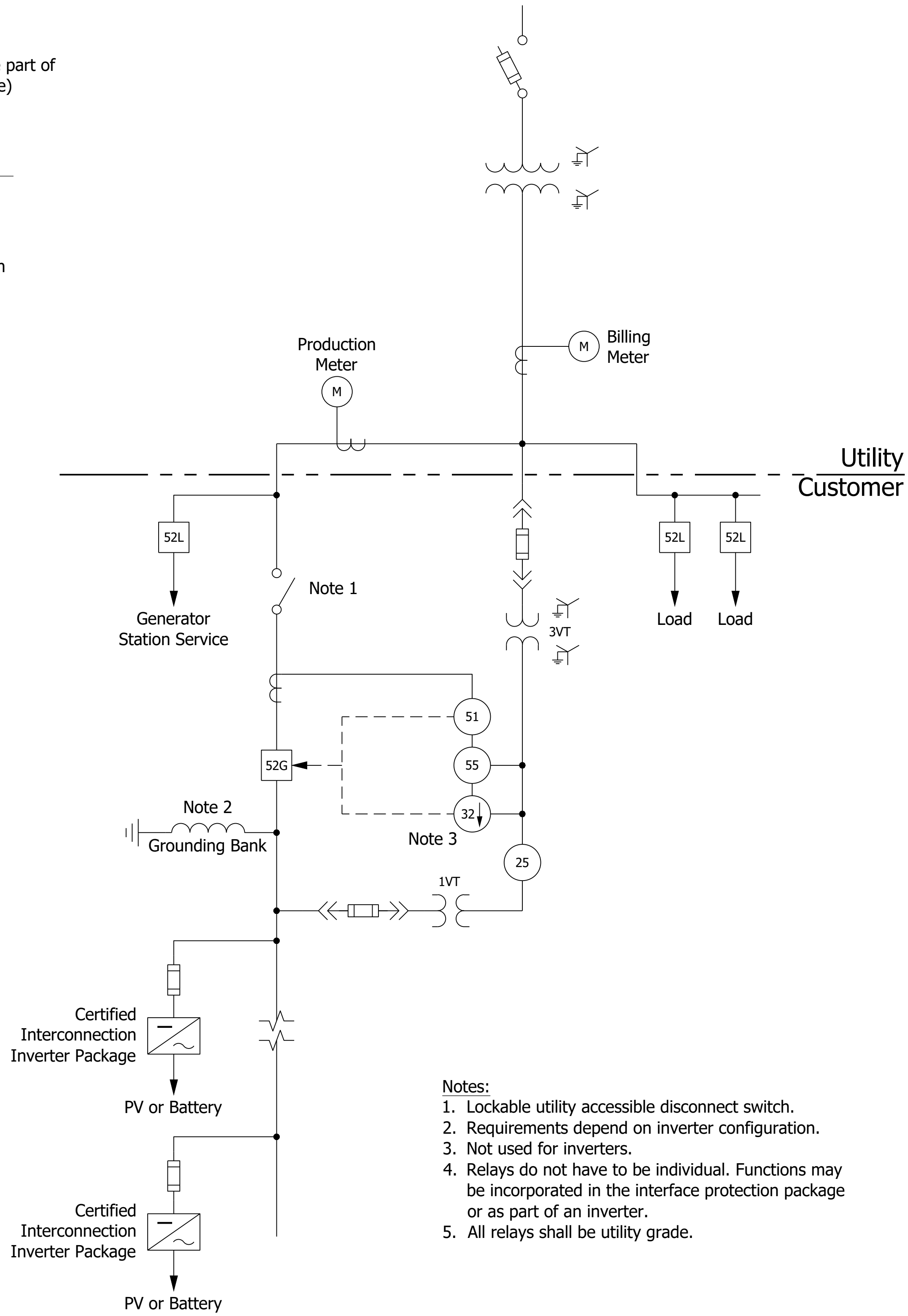
DATE: 06/10/2022	DRAWN BY: KI	APPROVED BY: DFJ	SCALE: None

Relay Elements

25 Synchronizer
32 Reverse Power
51 Overcurrent Relay (May be part of 52)
52 Circuit Breaker
  L = Load
  T = Transformer
  G = Generator
55 Power Factor Control (May be part of Inverter or Generator package)

Legend

#	Circuit Breaker
#	Relay Element
	Fused Disconnect Switch
	Disconnect Switch
	Fuse, draw out type
	Potential Transformer
	Transformer
	Capacitor Bank
M	Meter
	Ground, earth



Notes:
1. Lockable utility accessible disconnect switch.
2. Requirements depend on inverter configuration.
3. Not used for inverters.
4. Relays do not have to be individual. Functions may be incorporated in the interface protection package or as part of an inverter.
5. All relays shall be utility grade.

PSE
Power System Engineering, Inc.

Sample One-Line Diagram for Certified Inverter Package Installations

200kW to less than 1MW

(Figure 6)

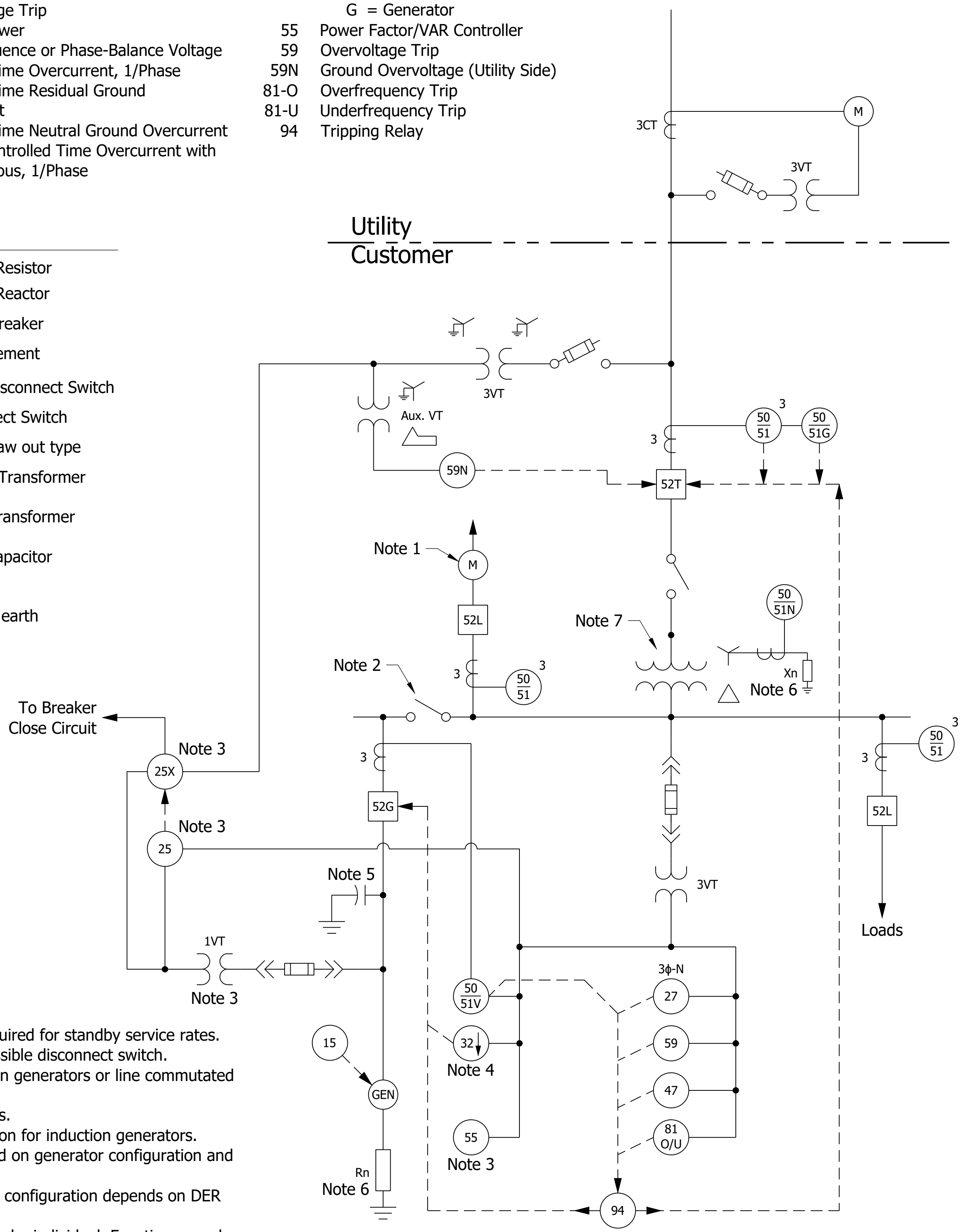
DATE: 06/10/2020	DRAWN BY: KI	APPROVED BY: DFJ	SCALE: None

Relay Elements

15	Speed Matching for Induction Gen	52	Circuit Breaker
25	Synchronizer		L = Load
25X	Sync Check		T = Transformer
27	Undervoltage Trip		G = Generator
32	Reverse Power	55	Power Factor/VAR Controller
47	Phase-Sequence or Phase-Balance Voltage	59	Overvoltage Trip
50/51	Inst. and Time Overcurrent, 1/Phase	59N	Ground Overvoltage (Utility Side)
50/51G	Inst. and Time Residual Ground Overcurrent	81-O	Overfrequency Trip
		81-U	Underfrequency Trip
50/51N	Inst. and Time Neutral Ground Overcurrent	94	Tripping Relay
50/51V	Voltage Controlled Time Overcurrent with Instantaneous, 1/Phase		

Legend

Rn	Neutral Resistor
Xn	Neutral Reactor
#	Circuit Breaker
#	Relay Element
	Fused Disconnect Switch
	Disconnect Switch
	Fuse, draw out type
	Voltage Transformer
	Power Transformer
	Shunt Capacitor
M	Meter
	Ground, earth



Notes:

1. Metering may be required for standby service rates.
2. Lockable utility accessible disconnect switch.
3. Not used for induction generators or line commutated inverters.
4. Not used for inverters.
4. Power factor correction for induction generators.
5. Requirements depend on generator configuration and step-up transformer.
6. Transformer winding configuration depends on DER facility design.
7. Relays do not have to be individual. Functions may be incorporated in the interface protection package or as part of an inverter.
8. Production meters telemetry is not shown.
9. All relays shall be utility grade.
10. Design must meet the DER Technical Standards.

Power System Engineering, Inc.

Sample One-Line Diagram for DER Interconnection

1MW to less than 10MW

(Figure 7)

DATE: 06/10/2022	DRAWN BY: KI	APPROVED BY: DFJ	SCALE: None