414 Nicollet Mall
Minneapolis, MN 55401

March 2, 2021

—Via Electronic Filing—

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: ADDITIONAL INFORMATION
IN THE MATTER OF A FORMAL COMPLAINT AND REQUEST FOR EXPEDITED RELIEF BY SUNRISE ENERGY VENTURES LLC AGAINST NORTHERN STATES POWER COMPANY
DOCKET NO. E002/C-20-892

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy (Company), submits additional "late filed" documents pursuant to Minnesota Rule 7829.0420. Xcel Energy submits these late filed documents related to arguments first raised by Sunrise Energy Ventures, LLC ("Sunrise") in its Reply Comments filed on January 19, 2021 concerning the content of the TSM (Technical Specifications Manual) and our tariffs. January 19 was the last day for filing comments, so we could not have filed the attached documents within the time allowed for comments.

We attach the following documents that are relevant to the Sunrise argument and that may assist the Commission in determining whether it is in the public interest to consider the Sunrise Complaint:

- **Attachment A:** Technical Specifications Manual (TSM)
- **Attachment B:** TIIR (Technical Interconnection and Interoperability Requirements)
- **Attachment C:** Tariff Sheet 6-33

We have electronically filed this letter with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service list. Please contact Jessica Peterson at Jessica.k.peterson@xcelenergy.com or (612) 330-6850 if you have any questions regarding this filing.

Sincerely,

/s/

JAMES DENNISTON
ASSISTANT GENERAL COUNSEL

Enclosures
c: Service List

Xcel Energy
Technical Specifications Manual
(TSM)

For the Interconnection and Operation of Distributed Energy Resources
with the Xcel Energy Distribution System
in Minnesota

Ver: May 1, 2020

Table of Contents

1 Introduction

This Technical Specifications Manual (TSM) contains utility-specific standards and requirements to be used in conjunction with the Minnesota Technical Interconnection and Interoperability Requirements (TIIR) for Distributed Energy Resources (DER). This TSM is only applicable to DER applications which are governed by the Minnesota Distributed Energy Resources Interconnection Process (MN DIP).

As set forth in the January 22, 2020 Order of the Minnesota Public Utilities Commission in Docket Nos. E999/CI-01-1023 and E99/CI-16-521, the TIIR and TSM are both included as part of the “Minnesota Technical Requirements” applicable to interconnections (and interconnection applications) subject to the MN DIP. The TSM must not be more restrictive than the standards contained in the TIIR. This order also outlined a process for providing interim guidance for how the transition from the 2004 Interconnection Standards’ Technical Requirement to the new Minnesota Technical Interconnection and Interoperability Requirements will occur. As IEEE 1547-2018 certified inverters are not yet readily available, this guidance is needed. The TSM reflects the latest version of the Interim Guidance filed on April 27th, 2020, under Docket Nos. E999/CI-01-1023 and E99/CI-16-521.

Updates to this TSM may impact safety and reliability, and the Area EPS Operator must be able to quickly address these issues. Each time this TSM is updated, the Area EPS Operator will make an informational filing with the Minnesota Public Utilities Commission and provide an informational notice with the webpage link.

The Area EPS Operator makes available to Interconnection Customers the TSM so that consistent and clear expectations can be set for all DER interconnections. However, this document cannot be used alone to design, build, and operate a fully compliant DER. The TIIR, applicable tariffs, Area EPS Operator’s Standard for Electric Installation and Use, and other industry standards such as the NEC and IEEE Standards will need to be referenced to ensure full compliance with all requirements. Where practical, some portions of these requirements are reproduced here, but the breadth of all possible DER configurations are too numerous to list all applicable requirements. As well, size and location of each DER on the Area EPS will result in unique operating requirements for each system. Given the nature of this document, the Area EPS Operator shall have sole authority on how the provisions of the TSM should be interpreted and applied. Nothing in the TSM is inconsistent with MN DIP 5.3 that sets forth the process and Commission authority for dispute resolution of all disputes arising out of the MN DIP interconnection process.

Where applicable, the MN DIP or MN DIA may include specific requirements for each unique DER installation. The TSM may provide a range of possible settings for the DER, or a default setting when no range is specified.

2 Abbreviations and Common Terms

Various abbreviations are used throughout this document. Certain of these are set forth below in this section. Other abbreviations in this TSM are consistent with the abbreviations used in the MN DIP, MN DIA, TIIR and general understanding in the industry.

AGIR	Authority Governing Interconnection Requirements
Area EPS Operator	The Area EPS that operates the distribution system. In this document the Area EPS Operator is Xcel Energy
BPS	Bulk Power System
DER	Distributed Energy Resource
EPS	Electric Power System
ESS	Energy Storage System
MN DIA	Minnesota Distributed Energy Resource Interconnection Agreement
MN DIP	Minnesota Distributed Energy Resource Interconnection Process
PoC	Point of Distributed Energy Resource Connection
PCC	Point of Common Coupling
RPA	Reference Point of Applicability
RTO	Regional Transmission Operator
MN DER TIIR	Minnesota Distributed Energy Resource Technical Interconnection and Interoperability Requirements
TPS	Transmission Power System
TSM	Technical Specifications Manual

3 Performance Category Assignment

The Area EPS Operator performance categories are provided in the MN DER TIIR, with no additional requirements for inclusion in the TSM at this time. Performance Category Assignment is currently not enforced.

3.1 Normal – Category A and B

The Area EPS Operator currently follows the MN DER TIIR for category assignment.

3.2 Assignment of Abnormal Performance Category I, II or III

The Area EPS Operator currently follows the MN DER TIIR for abnormal performance categories at this time.

4 Reactive Power Capability and Voltage/Power Control Performance

DER causing fluctuating and elevated voltages on the Area EPS beyond acceptable levels must be mitigated. To assist in mitigating these, a constant fixed power factor setting can be used. Other inverter-based reactive/active power mitigation strategies exist, but are not certified under an IEEE 1547.1 test protocol at this time. Once 1547.1-2020 is fully adopted by UL 1741, certified devices using these strategies will begin to become available. This section will also be updated to reflect the changes in available technology when the MN PUC deems inverters certified to these updated standards are readily available.

4.1 Constant Fixed Power Factor

Inverter-based DER shall be capable of providing a constant fixed power factor from 0.90 leading (absorbing) to 0.90 lagging (injecting).

Synchronous machine DER shall be designed to be capable of operating between 0.90 leading (absorbing) to 0.95 lagging (injecting).

The required constant fixed power factor value will depend greatly on the size and location of the DER within the Area EPS. For larger DER that proceed through the System Impact Study phase of the interconnection process, a specified constant fixed power factor will often be identified in the study results and indicated in the Operating and Maintenance Requirement (which is Attachment 5 to the MN DIA). Under the terms of the Operating and Maintenance Requirements Area EPS Operator may provide notice of a change to this value, and the DER needs to implement this change. The DER must constantly apply the then-current “constant fixed power factor value”. The then-current value is the value set in the Operating and Maintenance Requirements (without any notice being sent by Area EPS Operator changing that value), or is the value set in the most recent notice from Area EPS Operator changing the value.

However, for DER that do not have a MN DIA (such as those that only use the Uniform Statewide Contract as the Interconnection Agreement), the default settings in Table 1 shall be used. This constant fixed power factor shall be maintained at the RPA.

DER System (kVA AC)	Power Factor	Reactive Power Control
< 40 kVA	0.98	Absorbing reactive power
40 kVA to < 250 kVA	0.98	Absorbing reactive power
250 kVA to < 5 MVA	0.98	Absorbing reactive power
5 MVA to 10 MVA	0.98	Absorbing reactive power

Table 1: Constant Fixed Power Factor Requirements

If a DER requires a Power Factor different from 0.98 absorbing reactive power, then the Interconnection Customer cannot use the Uniform Statewide Contract as the Interconnection Agreement and will need to have a MN DIA as the Interconnection Agreement that includes the proper Power Factor, even if the Interconnection Customer was previously using the Uniform Statewide Contract as the Interconnection Agreement.

4.2 Voltage-Reactive Power Control

The Area EPS Operator requires the settings for Voltage-Reactive Power Control, also known as Volt-Var, to be disabled.

4.3 Voltage-Active Power Control

The Area EPS Operator requires the settings for Voltage-Active Power control, also known as volt-watt, to be disabled.

5 Response to Abnormal Conditions

Abnormal conditions can arise on the Area EPS, TPS, or BPS, for which the DER shall appropriately respond. Until IEEE 1547-2018 certified inverters are deemed readily available, DER shall be able to meet the requirements of IEEE 1547-2003 for response to abnormal conditions.

Multiple certifications currently exist for UL 1741 certified inverters. One of these certifications includes UL 1741 SA (CA Rule 21 and HI Rule 14H). While UL 1741 SA provides some functionality that is present in IEEE 1547-2018, this additional functionality shall be disabled for interconnection with the Area EPS Operator. Pre-loaded settings may also be present on inverters certified to UL 1741 SA that do not align with the settings contained in this section. In order to best serve the current DER conditions in Minnesota, these parameters shall be reviewed and set to the settings defined here and in the interim TIIR adoption addendum by the Interconnection Customer.

5.1 Abnormal Voltages

For all inverter-based DER, the DER shall trip for the voltage conditions in Table 2. The DER is not required to ride-through during this time period, but shall trip within the clearing time indicated.

Shall Trip – Inverter DER		
Shall Trip Function	Default Setting	
	Clearing time (s)	Voltage (p.u. of nominal voltage)
UV2	0.16	0.50
UV1	2.0	0.88
OV1	1.0	1.10
OV2	0.16	1.20

Table 2: Inverter DER Voltage Abnormal Response

For all synchronous machine-based DER, the DER shall trip for the voltage conditions in Table 3. The DER is not required to ride-through during this time period, but shall trip within the clearing time indicated.

Shall Trip – Synchronous DER		
Shall Trip Function	Default Setting	
	Clearing time (s)	Voltage (p.u. of nominal voltage)
UV2	0.16	0.50
UV1	2.0	0.88
OV1	1.0	1.10
OV2	0.16	1.20

Table 3: Synchronous Machine DER Abnormal Voltage Response

5.2 Abnormal Frequency

All DER types shall trip for abnormal frequency conditions in Table 4. The DER is not required to ride-through during this time period, but shall trip within the clearing time indicated.

Shall Trip Function	Default Setting	
	Clearing time (s)	Frequency (Hz)
UF1	0.16*	59.3
OF1	0.16	60.5

Table 4: Abnormal Frequency Response

*The Area EPS may need to adjust this time to coordinate with typical regional under frequency load shedding programs and expected frequency restoration time.

5.3 Dynamic Voltage Support

Dynamic Voltage Support shall be disabled.

6 Protection Requirements

The Interconnection Customer shall provide protective devices and systems to detect the Voltage, Frequency, Harmonic and Flicker levels as defined in the IEEE 1547-2003 standard during periods when the DER is operated in parallel with the Area EPS Operator. The Interconnection Customer shall be responsible for the purchase, installation, and maintenance of these devices.

In general, an increased degree of protection is required for increased DER size and can vary based on DER technology and risk to the Area EPS. Risk to the Area EPS increases due to conditions such as a greater magnitude of short circuit current, the potential impact to system stability, and potential impacts to power quality. Medium and large DER require more sensitive protection to minimize damage and ensure safety. Where a DER system may be constructed of UL 1741 certified inverters, the DER installation as a whole must be able to provide protections equivalent to IEEE 1547. In many cases, the inverter-based protective functions are not designed to provide protections when inverters are aggregated or supplemental devices are present. Additional relaying may be required to supplement the UL 1741 certified inverter functions in these cases.

The protection scheme shall be reviewed and approved by a Professional Engineer when a Professional Engineer is required for design of the DER as specified by MN DIP Section 1.5.1.4.

A copy of the protective settings, either internal to an inverter or through dedicated relaying and fusing, shall be made available to the Area EPS Operator upon request for review and approval.

6.1 Utility AC Disconnect

All DER are required to provide a manual disconnecting device capable of interrupting the rated generator and/or load current, accessible to the Area EPS Operator’s personnel 24/7 without escort, hindrance, or delay, which can be locked open, and provides a visible open. The visible open shall be viewable without unbolting covers or without assistance from site personnel.

The Utility AC Disconnect shall be located between Area EPS Operator owned equipment and the DER. For example, if a production meter is present, the disconnect shall be located between the production meter and the DER.

The Utility AC Disconnect shall be located no more than 10 feet from the main service meter. If the disconnect cannot be located within 10 feet of the main service meter, either due to the location of the production meter or other physical constraints, permanent, weatherproof labelling in the form of a map or diagram shall be provided at the main service meter indicating the location of the Utility AC Disconnect.

6.2 Service Protection

6.2.1 Primary Service

All primary voltage electric services are required to provide overcurrent protection at the PCC to prevent tripping of Area EPS Operator-owned protective devices for failure of customer-owned equipment. Coordination between 12 and 15 cycles between the Area EPS Operator-owned overcurrent device and the customer-owned overcurrent device shall be maintained. When other protective devices are present or functions enabled, the DER device shall always be faster than the Area EPS Operator-owned device.

6.2.2 Secondary Services

All secondary voltage electric services are required to install protective devices per the NEC. All DER shall be located behind protection meeting this standard.

If a supply-side tap is used for DER interconnection, a protective device must immediately follow the tap.

6.3 Protective Devices

When the DER site installs protective devices, the following requirements shall apply.

6.3.1 Relays

1) All equipment providing relaying functions shall meet or exceed ANSI/IEEE Standards for protective relays.

2) Required relays that are not “draw-out” cased relays shall have test plugs or test switches installed to permit field testing and maintenance of the relay without unwiring or disassembling the equipment. Inverter based protection is excluded from this requirement.

3) Three-phase interconnections shall utilize three-phase power relays, which monitor all three phases of voltage and current.

4) All relays shall be equipped with setting limit ranges at least as wide as specified in IEEE 1547-2003, and meet other requirements as specified in the Area EPS Operator System Impact Study and this TSM. Setting limit ranges are not to be confused with the actual relay settings required for the proper operation of the installation. At a minimum, all protective systems shall meet the requirements established in IEEE 1547-2003.

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

   b. Over-voltage relays (IEEE Device 59) shall operate to disconnect the DER from the Area EPS per the requirements of Section 5.1 in this TSM.

   c. Under-voltage relays (IEEE Device 27) shall operate to disconnect the DER from the Area EPS per the requirements of Section 5.1 in this TSM.

   d. Over-frequency relays (IEEE Device 81O) shall operate to disconnect the DER from the Area EPS per the requirements of Section 5.2 in this TSM.

   e. Under-frequency relay (IEEE Device 81U) shall operate to disconnect the DER from the Area EPS per the requirements of Section 5.2 in this TSM. The Area EPS Operator will provide the reference frequency of 60 Hz. The DER control system must be used to match this reference. The protective relaying in the interconnection system will be expected to maintain the frequency of the output of the DER.

f. Reverse power relays (IEEE Device 32) (power flowing from the DER to Area EPS Operator) shall operate to disconnect the DER from the Area EPS for a power flow to the Area EPS with a maximum time delay of 2.0 seconds.

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

h. Transfer Trip – All DER are required to disconnect from the Area EPS Operator when the Area EPS Operator system is disconnected from its source, to avoid unintentional islanding. With larger DER, which remain in parallel with the Area EPS Operator, a transfer trip system may be required to sense the loss of the Area EPS Operator source. See Section 9.2 for more details. For some installations the alternate Area EPS Operator source(s) may not be utilized except in rare occasions. If this is the situation, the Interconnection Customer may elect to have the DER locked out when the alternate source(s) are utilized, if agreeable to the Area EPS Operator.

i. Parallel limit timing relay (IEEE Device 62PL) set at a maximum of 120 seconds for soft transfer installations and set no longer then 100ms for quick transfer installations, shall disconnect the DER from the Area EPS on limited parallel interconnection systems. Power for the 62PL relay must be independent of the transfer switch control power. The 62PL timing must be an independent device from the transfer control and shall not be part of the DER PLC or other control system.

6.4 Required Protective Devices

Table 5 shows the required protective devices for DER. These functions shall be made available either through protective relays, or through protective functions made available by an inverter, provided those functions have been certified through UL 1741. Descriptions of the types of interconnections can be found in Appendix A.

Type of Interconnection	Over current (50/51)	Voltage (27/59)	Frequency (81 0/U)	Reverse Power (32)	Lockout (86)	Parallel Limit Timer	Sync-Check (25)	Transfer Trip
Open Transition Mechanically Interlocked (Fig. 1)	—	—	—	—	—	—	—	—
Quick Open Transition Mechanically Interlocked (Fig. 2)	—	—	—	—	Yes	Yes	Yes	—
Closed Transition (Fig. 2)	—	—	—	—	Yes	Yes	Yes	—
Soft Loading Limited Parallel Operation (Fig. 3)	Yes	Yes	Yes	Yes	Yes	Yes	Yes	—
Soft Loading Extended Parallel < 250 kW (Fig. 4)	Yes	Yes	Yes	—	Yes	—	Yes	—
Soft Loading Extended Parallel >250kW (Fig.4)	Yes	Yes	Yes	—	Yes	—	Yes	Yes
Inverter Connections (Fig. 5)								
< 40 kW	Yes	Yes	Yes	—	Yes	—	—	—
40 kW - 250kW	Yes	Yes	Yes	—	Yes	—	—	—
> 250 kW	Yes	Yes	Yes	—	Yes	—	—	Yes

Table 5: Summary of Relaying Requirements

6.5 Secondary Networks

Per TIIR Section 7.4, additional protection may be required for secondary network interconnections. The following sections describe when additional protection is needed for interconnections on Secondary Networks, and what additional protections are required.

A DER shall be UL 1741 certified if interconnected with a secondary network. Rotating machines will not be approved for parallel interconnection to the secondary network. Open transition DER as described in Appendix A are allowed to be installed for a secondary network Interconnection Customer, as the DER does not parallel with the Area EPS at any time.

If, after the initial application and approval for interconnection, a Secondary Network-connected DER without minimum load relaying results in notable adverse Secondary Network impacts due to a reduction in load or other system changes, the DER shall be required to install minimum load relaying at cost to the Interconnection Customer.

6.5.1 Spot Networks

A spot network is a small Secondary Network, usually at one location, consisting of two or more primary feeders, with network units (consisting of transformers, relays, and network protectors) with one or more load service connections. Typically, these feed one customer or part of a building; some may serve more than one building.

Additional protection shall be installed as described in Section 6.5.3 when any of the following circumstances are true for interconnections to a spot network:

- When the DER AC maximum capacity is greater than 6.6% of the Interconnection Customer's minimum service load, where service load is considered the Interconnection Customer's single-metered real time load without DER load reductions. Minimum service load may be determined from daytime hours if the DER type is photovoltaic.
- When the aggregate DER AC maximum capacity is greater than 5% of the spot network's maximum load
- When the aggregate DER AC maximum capacity is greater than 50 kW

6.5.2 Grid Networks

A grid network is a secondary network with multiple wires interconnected to separate network units (consisting of transformers, relays, and network protectors) designed to service multiple geographically separate customers. These are often referred to as an area networks or street networks. A grid network will be treated as a spot network if there are less than three delivery points.

Additional protection shall be installed as described in Section 6.5.3 when any of the following circumstances are true for interconnections to a grid network:

- When the DER AC maximum capacity is greater than 10% of the Interconnection Customer's minimum service load. Minimum service load may be determined from daytime hours if the DER type is photovoltaic.
- When the aggregate DER AC maximum capacity is greater than 5% of the grid network's maximum load
- When the aggregate DER AC maximum capacity is greater than 250 kW

6.5.3 Minimum Load Relaying Options

If the proposed DER is required to install additional protection per Sections 6.5.1 and 6.5.2, one of the minimum load relaying options listed below shall be installed. All relays shall meet or exceed ANSI/IEEE Standards for protective relays. All relaying described here shall utilize three-phase monitoring. Minimum load relaying shall use instantaneous elements with no time delay to trip or curtail DER.

Minimum load relaying ensures minimum power consumption and is intended to prevent unnecessary network loss due to the potential of power flow back into the Secondary Network from DER. Two types of relay schemes to ensure minimum power consumption are the Minimum Import Relay (MIR) and Comparative Relay (CR).

DER controlled dynamically through the use of a Power Control System meeting the requirements in Section 8 can be utilized in combination with minimum load relaying to curtail DER output prior to the minimum load relays operating. Due to the inability of network protectors to function properly in reverse flow conditions, inadvertent export as described in Section 8.4 is not allowed on Secondary Networks. Where the impact of an unintentional operation of a network protector is limited to the

Interconnection Customer’s facility, DER with minimum load relaying functionality may be used upon review and approval by Xcel Energy.

6.5.3.1 Minimum Import Relay (MIR)

- MIR shall monitor Interconnection Customer’s service load.
- MIR shall trip or curtail DER below set limits when Interconnection Customers’ service load drops to less than 200% of DER system AC rating.
- For spot networks, relay settings shall be checked against minimum load.

6.5.3.2 Comparative Relay (CR)

- CR shall monitor Interconnection Customer’s service demand, where service demand is considered the Interconnection Customer’s single-metered real time load including DER load reductions.
- CR shall monitor the aggregate AC DER output of the Interconnection Customers installed DER.
- CR shall trip or curtail DER output below set limits when DER output is greater than 100% of service demand. Relay shall trip DER prior to reaching the relaying systems sensitivity or accuracy limits, plus an amount determined by the largest circuit verification.
- For sport networks, relay settings shall be checked against minimum load.

6.5.3.3 Other Proposed Control and Relaying Schemes

New technologies may become available meeting the intent of minimum load relaying described in Sections 6.5.3.1 and 6.5.3.2. An exemption request by the Interconnection Customer for Area EPS grade[1] control and relaying schemes meeting the intent of IEEE 1547.6 and the requirements in this TSM may be submitted. The exemption may be granted upon review and approval by an Xcel Energy engineer. Such requests shall be made during the application process.

[1] Meet or exceed ANSI/IEEE Standardes for protective relays, i.e., C37.90, C37.90.1 and C37.90.2

6.6 Additional Protection

The DER site is required to remain compliance with IEEE 1547, not cause voltages to exceed ANSI C84.1 ranges, and prevent detrimental power quality impacts as a result of DER operation. Each DER site will be unique in its impact to these requirements, and will need to be carefully reviewed by the Interconnection Customer for such potential impacts.

Most commonly, for DER sites 100 kW or larger, additional overvoltage relaying and relaying to detect and trip for open phase events are installed at the DER site, although other DER designs may require additional protections. Additional devices may serve as supplemental protection to existing functionality in a certified inverter. The entire DER site shall maintain compliance with the applicable standards, regardless of which device is providing the primary protective function. Should the DER site be non-compliant during its operation, it shall cease operation until such compliance is adequately demonstrated to the Area EPS Operator.

6.7 Open Phase Protection

For open phase detection and tripping, devices relying on under voltage to detect an open phase will often not be appropriate due to the presence of delta or zig-zag transformer windings on the DER site. These windings often allow for voltage regeneration on the open phase, defeating the under voltage relaying scheme. Additionally , for an open phase, the use of a grounded wye-grounded wye three-leg core type step-up transformer can result in voltage re-generation magnetically through flux interactions rather than electrically. Core construction must be considered. The Area EPS Operator has no preferred method for open phase protection, if the DER site is compliant with IEEE 1547 requirements at the PCC.

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

Typical inverter-based configurations that require additional relaying include:

- Configurations with zig-zag or grounded wye-delta grounding banks
- Configurations with delta windings on onsite transformers.
- Configurations with grounded wye-grounded wye three-leg core step-up transformer

(1) As required by IEEE 1547.1, all DER must detect open phase conditions when output is as low as 5% of rated output current, or at the minimum output current if the minimum output current is greater than 5% of the rated output current.

(2) The Area EPS Operator does not recommend a specific method for detecting an open phase condition, as there are many acceptable methods for achieving this. Positive-sequence phase balance, zero-sequence detection and under voltage relaying are often deficient protective schemes for the purpose of detecting and tripping for an open phase on variable DER systems 100 kw or greater. Several issues need to be considered:

a. Positive-sequence phase balance and zero-sequence detection must set pickup levels above the inherit imbalance on the Area EPS to avoid nuisance tripping. This pickup level will often be too high to allow the protective system to identify an open phase condition when the DER is at 5% rated output current.

b. As some inverters can supply negative-sequence current, inverter characteristics should be fully understood before utilizing negative sequence detection. Time delays shall be coordinated with Area EPS protection. Generally, a one second delay is sufficient.

c. Loss of phase via under voltage relaying detection is inadequate for identifying an open phase condition. Ground banks, delta windings, and use of grounded wye-grounded wye three-leg core transformers, present on both the DER site and on the larger Area EPS, may reconstruct voltage on the open phase.

6.8 Grounding

Xcel Energy operates an effectively grounded system, as defined by IEEE standards, on most of its distribution system and requires that DER connected to the Company’s system be designed (through the selection of transformers, generator grounding, etc.) so that they contribute to maintaining an effectively grounded system. A DER facility that does not participate in maintaining effective grounding, upon islanding, can cause severe overvoltages to single phase loads, resulting in equipment damage. Smaller, single-phase inverter-based DER facilities are excluded from this requirement.

Neutral reactors are required in a number of configurations for both rotating generators 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 shall exceed the with-stand 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 saturated under fault conditions. The lesser of 125% of current times reactance or full line-neutral voltage is suggested.

All electrical equipment shall be grounded in accordance with local, state, and federal electrical and safety codes and applicable standards.

Grounding of sufficient size to handle the maximum available ground fault current shall be designed and installed to limit step and touch potentials to safe levels. It is the responsibility of the Interconnection Customer to provide the required grounding for the DER.

6.8.1 Inverter-Based DER

DER presents risk for temporary overvoltages to occur between the time the Area EPS source is lost and the DER disconnects from the Area EPS, due to a loss of ground reference. Ground reference transformers prevent this from occurring, as well as providing additional benefits, such as possible ferroresonance dampening. Ground reference transformers shall be designed and installed by the Interconnection Customer for all DER 100 kW or greater, or when the aggregate of all DER onsite is 100 kW or greater.

For inverter-based DER, much ongoing research is still occurring in regards to effective grounding. However, some current best practices have been developed. For inverter based DER, the following requirements shall be met:

1) $X_{0,DER}$= 0.6 p.u. +/- 10% (Note: 1 p.u. is based on $Z_{base} = \frac{kV^2}{MVA_{DER}}$)

2) $\frac{X_{0,DER}}{R_{0,DER}} \geq 4$ (Note: this value does not have a +/- 10% tolerance, it shall be ≥4)

3) Ground referencing equipment shall be designed to withstand a minimum of V_0=4% and remain connected (Note: I_0 can be approximated as $I_0=V_0/Z_0$).

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

5) Loss of ground referencing equipment shall immediately trip the DER.

6.8.2 Single-Phase Inverters

Three-phase DER facilities comprised of single-phase inverters must comply with NEC (2014) 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 DER 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 requirements as stated in the Xcel Energy Standard for Installation and Use shall cease operation until a balance better than the Standard’s minimum requirements can be met.

6.8.3 Synchronous and Induction Machine-Based DER

For machine-based DER, effective grounding shall comply with traditional IEEE grounding standards. To achieve effective grounding, an Interconnection Customer's system equivalent (Thevenin equivalent impedance) must meet the two criteria given below or otherwise meet a coefficient of grounding of 80%, also see IEEE 32 and IEEE C62.92.2. Note – the effective grounding impedance is always determined with the generator separated from the Area EPS. Momentary fault withstand and continuous current ratings are always determined with the Area EPS and generator connected.

a) The positive sequence reactance is greater than the zero sequence resistance ($X1 > R0$).

b) The zero sequence reactance is less than or equal to three times the positive sequence reactance. *The Area EPS Operator 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.*

When calculating faults and effective grounding using the positive, negative, and zero sequence impedance networks, the networks shall include impedances for the following: the step-up transformer, generator subtransient 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 subtransient reactance shall be used. If the Xd” equivalent is not available, the following approximation is usually adequate: X = (Rated Voltage / Locked Rotor Current) ohms.

The Interconnection Customer shall submit the grounding device information for approval before it is purchased. Many different system configurations will meet the effective grounding requirements. Listed below are some guidelines and restrictions.

1) A grounded-wye/grounded-wye step-up transformer is common. When this transformer arrangement is used, the generator must have an appropriately sized grounding bank, or the generator’s neutral must be adequately grounded (typically through a grounding reactor) to meet the Area EPS Operator's requirements for effective grounding. The Area EPS Operator supplied three-phase service transformers are grounded-wye/grounded-wye for four-wire systems.

2) A delta (gen)/grounded-wye (system) step-up transformer must have a reactor in its grounded-wye neutral connection to meet the Area EPS Operator’s requirements for effective grounding or a separate ground bank, *(2.0*X1 < Xo < 2.5*X1).* A neutral resistor will cause high power losses and is not recommended. Area EPS Operator does not supply this configuration.

3) A delta step-up transformer, with delta on the Area EPS Operator’s distribution feeder 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 Area EPS Operator’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 generator and ground source during system separation. Area EPS

Operator supplied three-phase service transformers are generally delta on the Area EPS side for three-wire systems.

4) Generators 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 Area EPS Operator's effective grounding requirements. Grounding the generator is not recommended since significant generator derating due to unbalanced currents may result.

5) Voltage imbalance on the Area EPS Operator's distribution system may result in substantial current flowing into an Interconnection Customer's generator(s) or grounding equipment. The Area EPS Operator'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 Interconnection Customer's equipment must be able to withstand allowable voltage imbalances and be able to operate during an imbalance condition. A V_0 sequence voltage of 4% is recommended for determining the continuous imbalance rating. This rating shall be adequate for contingency system configurations.

   Normal system source impedance data for a given location can be obtained from the Area EPS Operator's Area Engineer. For contingencies and maintenance, field ties are temporarily used and this can change the source impedance and fault duties as seen by an Interconnection Customer. Normal system source impedance shall be obtained before an Interconnection Customer 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 Operations

7.1 Enter Service

The DER shall delay entry into service by an intentional minimum delay of 300 seconds when the Area EPS Operator Distribution System steady state voltage and frequency are within the default ranges specified in Section 4.2.6 of IEEE 1547-2003, unless otherwise specified by Attachment 5 of the MN DIA. This entry into service requirement shall also apply for return to service after a DER trips.

7.2 Ramp Rates

To prevent a sudden increase in DER output that could cause impacts to power quality of the Area EPS, DER with multiple inverters on site shall randomly stagger the enter service time of each inverter, after the minimum delay for entry into service of Section 7.1 has elapsed, unless otherwise specified by Attachment 5 of the MN DIA.

7.3 Power Quality

DER shall not cause any significant reduction in the quality of service being provided to other customers. Certified inverters, unless they are malfunctioning or misapplied, will generally comply with these requirements. Abnormal voltages, frequencies, harmonics, or interruptions must be kept within limits specified under IEEE 1547 and IEEE 519. If high or low voltage complaints, transient voltage complaints, and/or harmonic (voltage distortion) complaints result from operation of a DER, such DER equipment may be disconnected from the Area EPS until the Interconnection Customer resolves the problem. The Interconnection Customer 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.

7.3.1 Voltage

Operation of the DER shall not adversely affect the voltage stability of the Area EPS. The facility shall not actively regulate the feeder voltage or cause it to go outside of ANSI C84.110 Range A.

The DER shall operate in a manner that does not cause Rapid Voltage Change or Flicker violations in accordance with Xcel Energy’s implementation of IEEE 1453.

7.3.2 Harmonics

The Total Demand Distortion (TDD) from the facility will be measured at the facility's metering point or point of common coupling (PCC). Harmonics on the power system from all sources must be kept to a minimum. Under no circumstances may the harmonic current distortion, originating from the DER, be greater than the values listed in IEEE 1547.

In addition, any interference with other customer’s equipment or communications caused by the DER’s harmonics in excess of federal, state, and local codes will be resolved at the Interconnection Customer's expense.

7.4 Periodic Testing & Record Keeping

The DER Operator shall notify the Area EPS Operator 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.

Prior to modifications to the DER triggering reverification, the DER Operator shall notify the Area EPS Operator's interconnection coordinator, as identified on the Area EPS Operator's website. Any of the above events may be cause for requiring reverification of the interconnection and interoperability requirements.

All interconnection-related protection and control systems shall be periodically tested and maintained, by the Interconnection Customer, at intervals specified by the manufacturer or system integrator and shall not exceed 10 years. Periodic test reports and a log of inspections shall be maintained by the Interconnection Customer and made available to the Area EPS Operator upon request. The Area EPS Operator shall be notified prior to the testing of the protective and control systems to witness the testing if so desired. The testing procedure for re-test shall be a functional test of the protection and control systems.

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

7.5 O&M Agreements

DER systems that operate in parallel and do not have the Uniform Statewide Contract as the only Interconnection Agreement will use the MN DIA as the Interconnection Agreement. Attachment 5 to the MN DIA sets forth the Operating and Maintenance requirements of the DER. This Attachment 5 is created for the benefit of both the Interconnection Customer and the Area EPS Operator and will be agreed to between the Parties. This covers items that are necessary for reliable operation of the Local and Area EPS and are unique to each DER. The items included as operating requirements may not be limited to the items shown on this list:

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

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

3) Permitted and disallowed ESS Control Modes.

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

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

6) Response to control or communication failures.

7) Performance category assignments (normal and abnormal).

8) Dispatch characteristics of DER.

9) Notification process between DER Operator and Area EPS Operator.

10) Right of Access.

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

1) Routine maintenance requirements and definition of responsibilities.

2) Material modification of the DER that may impact the Area EPS.

8 Power Control Systems (PCS)

An Interconnection Customer may elect to use a Power Control System to achieve their interconnection goals, maintain compliance with applicable tariffs, or some Area EPS Operator requirements. Power Control Systems can be defined as hardware and software that is external to an inverter used to limit the export capability of the DER. A programmable logic controller or energy management system software controlling the output of a DER are examples of a PCS.

8.1 Power Control System Requirements

Power Control Systems shall meet the following requirements to be considered an allowable means of meeting an applicable tariff or Area EPS Operator requirement:

1) Shall monitor export or import of power at the PCC.

2) Shall control energy production of the DER, either by tripping or curtailing the energy production, within 2 seconds of receiving such a signal.

3) Shall monitor and respond to inadvertent export, as defined in Section 8.4.

4) Shall self-monitor the Power Control System, such that failure of the Power Control System to control or monitor will result in tripping of the DER or separation from the Area EPS. This includes loss of power to the Power Control System.

5) Shall lock down configurations that would modify a control mode, making accessible to only qualified personnel.

8.2 Common Operating 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 PCS. Most services provided by a PCS can be categorized into one of three common operating modes, although each service will have unique settings depending on the specific goal of the PCS. 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:

1) <u>Limited Export at the PCC</u>- The PCS controls the amount of real power that is exchanged across the PCC.

2) <u>Limited DER Output Capacity-</u> The PCS controls the amount of real power that the DER is capable of outputting at the PoC, behind the Interconnection Customer's side of the PCC.

3) <u>Import Only</u> - The PCS prevents DER from exporting real power across the PCC. This restriction may be placed on a single DER within a system of multiple DER, such as only on an ESS while allowing PV to export, or may be placed on all DER behind a single PCC.

8.3 Documentation

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

1) Manufacturer and model of the power control system, or of the components that make up the power control system.

2) User manual of the power control system.

3) A control schematic of the PCS, showing instrumentation, sensors, breakers, and DER.

4) A listing of the operating modes and services that will be available in the PCS.

5) A listing of the operating modes and services that will be enabled.

6) 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.

7) A description of how operating modes and services not being enabled are locked down to prevent unintentional enabling.

8) State the enabled operating mode, defined in Section 8.2, on the one-line diagram and interconnection application.

9) Additional information that may be requested by Area EPS Operator to clarify operation of the power control system.

8.4 Inadvertent Export

Inadvertent export is the unscheduled and uncompensated export of real power across the PCC generated from a DER’s parallel operation and delivered to the Area EPS Operator.

The Interconnection Customer remains responsible for inadvertent energy exports. For DER using a PCS, occasional de minimis “inadvertent export” of power is allowed. This recognizes that any parallel operation of a source with the Area EPS may encounter brief upsets due to feeder or customer disturbances, sudden load changes, etc.

The magnitude of export across the PCC shall be less than the total Distributed Energy Resource facility nameplate rating (kW-gross)[2]. The duration of export of power from shall be less than 30 seconds for any single event.

Inadvertent export events shall not exceed thermal, service voltage, power quality, or network limits defined within the Minnesota TIIR, this TSM, or Interconnection Agreements. When these constraints are identified by the Area EPS Operator, the inadvertent export shall be limited to 2 seconds. Unless a PCS meets the relaying requirements of Section 6.3 for reverse power relaying, a separate reverse power relay shall be installed for this function that meets the relaying requirements of Section 6.3.

The cumulative amount of energy from the Interconnection Customer delivered to the Area EPS Operator in any billing month shall be less than the on-site combined nameplate real power source ratings (kW-gross)[3] multiplied by one (1) hour.

Any amount of export of real power across the point of interconnection lasting longer than 30 seconds for any single event shall result in a cease-to-energize[4] of the Interconnection Customer’s energy sources within two (2) seconds of exceeding the 30-second duration limit.

Where applicable, any failure of the Interconnection Customer’s control system for thirty (30) seconds or more shall cause the Interconnection Customer’s energy sources to enter a non-export operational mode where no energy will be inadvertently exported to the Area EPS. Equipment considered part of the control system includes but is not limited to a PCS, internal transfer relay, energy management system, or other Interconnection Customer facility hardware or software system(s) intended to prevent the reverse power flow.

[2] The magnitude of export is based on the combined nameplate ratings of the sources that can actually be simultaneously supplied to the grid, such as storage and self-generation. If the contribution of the energy storage to the total contribution is limited by programing or by some other on-site limiting element, the reduced ongoing capacity will be used.
[3] The magnitude of export is based on the combined nameplate ratings of the sources that can actually be simultaneously supplied to the grid, such as storage and self-generation. If the contribution of the energy storage to the total contribution is limited by programing or by some other on-site limiting element, the reduced ongoing capacity will be used.
[4] Cessation of active power delivery under steady state and transient conditions and limitation of reactive power exchange. This may lead to momentary cessation or trip. This does not necessarily imply, nor exclude disconnection, isolation, or a trip. Limited reactive power exchange may continue as specified, e.g., through filter banks, or approved arrangement. Energy storage systems are allowed to continue charging (IEEE P1547/D6.2).

Ongoing efforts within the industry to better define allowable inadvertent export limits are on-going and changes and further refinement should be expected.

9 Interoperability

Per the interim adoption addendum Attachment 1, Section 9, Interoperability of the TIIR is not applicable in the interim period. The Area EPS Operator's TSM shall be used during this time. The Area EPS Operator's TSM will contain requirements comparable to Section 5 of the 2004 State of Minnesota Distributed Generation Interconnection Requirements document regarding monitoring and control requirements.

9.1 Remote Monitoring (Telemetry)

For all DER 250 kW or greater, remote monitoring of the DER production is required.

Remote monitoring is typically established with equipment internal to a main service meter or production meter. Monthly charges will be billed to the Interconnection Customer for remote monitoring.

9.2 Direct Transfer Trip

All DER are required to disconnect from the Area EPS Operator when the Area EPS Operator system is disconnected from its source. This is required to avoid unintentional islanding of the Area EPS. This disconnection can be accomplished in several ways. For many inverter-based DER, a UL 1741 certification provides assurance in most scenarios that the DER will disconnect from the Area EPS upon loss of the Area EPS source. For non-certified systems, and in some scenarios where certification of systems may be inadequate, disconnection is triggered by a direct transfer trip signal from the Area EPS that trips a customer-owned device, such as a breaker or recloser.

The need for transfer trip installation is dictated by the size and type of the DER in relation to minimum loading of the feeder, presence of large rotating loads, and existing DER size, type, and method for anti-islanding detection. In most scenarios, inverter-based DER using UL 1741 certified inverters will not require DTT. The system impact study will determine specific requirements.

When Direct Transfer Trip of the Interconnection Customer breaker is required, the Interconnection Customer shall make provisions for transfer trip. The provisions required for a typical, radio-type Direct Transfer Trip are as follows:

1) Facilities to mount an antenna that provides direct line of sight with the Substation the DER is interconnecting with. If this cannot be accomplished with existing customer facilities, a wooden pole will be required to be installed on the Interconnection Customer property. The pole may have a height of 100', but is often lower, depending on the geography of the surrounding area.

2) Space for an Area EPS Operator-owned communication cabinet is required.

3) 24/7, unescorted, drivable access shall be maintained for this equipment.

4) The Interconnection Customer shall own and maintain connection between two contacts at the communication cabinet. These contacts will be to:
   - (1) trip a breaker that disconnects the DER from the Area EPS,
   - (2) block the breaker from reclosing.

5) The entire direct transfer trip operation, including processing of signals and operation of the Interconnection Customer equipment in conjunction with Area EPS Operator equipment shall not exceed 2 seconds. Area EPS Operator can typically provide a DTT signal within 50-100msecs of an Area EPS Operator device being opened, but coordination with Area EPS Operator will be required to verify Interconnection Customer required trip times.

The Area EPS Operator makes every effort to use the least cost, most reliable technology for Direct Transfer Trip when possible. In some scenarios, the technology choice required may result in a customized solution with unique requirements of the Interconnection Customer to provide provisions for Direct Transfer Trip. As an example, Direct Transfer Trip via radio may not be adequate in hilly regions with a large distance between the DER site and interconnected substation. These will be determined and communicated with the Interconnection Customer by the Area EPS Operator when they are identified.

10 Energy Storage

Energy storage standards and best practices are a rapidly developing topic that will require this section to be updated sooner than other sections of this TSM. Interconnection of energy storage includes many factors in common with prevalent inverter based distributed resources, such as photovoltaic solar DER. Energy storage also introduces a few additional considerations which are detailed in this section. The types and use cases associated with ESS will continue to rapidly shift until standards and certifications are developed.

At the core of any ESS review is evaluation of export and import abilities that comply with tariff requirements. For example, currently, export of energy stored within an energy storage system into the Area EPS can only occur if that energy was originally generated from an onsite DER that qualifies for net-energy meter rates, such as PV. The ESS design is reviewed to ensure that all monitoring and control mechanisms are appropriately placed and enabled so as to provide the proper energy measurements and controls required to comply with an applied for configuration.

Many ESS vendors use unique control mode names that may have different meanings from vendor to vendor. The details of the control mode shall be evaluated against the eight configurations contained in Section 10.11.

10.1 Testing

ESS are subject to the testing and verification requirements in Section 13. Efforts should be made to test the DER system as a whole, with both the ESS and other DER being tested simultaneously to demonstrate compliance with IEEE 1547-2003.

10.2 Utility AC Disconnect

ESS are required to have a Utility AC Disconnect meeting the requirements of Section 7.1. However, if a Utility AC Disconnect is installed in a location such that it will isolate all DER and still meet the requirements in Section 7.1, a single disconnect can be used. If possible, this disconnect should be located upstream of any device that automatically opens in the event of loss of the Area EPS source, such as an automatic transfer switch. This will allow for a more robust witness test, and will allow the Interconnection Customer to remain energized when the Area EPS Operator needs to establish a visible open from the energy sources. The Area EPS Operator is not responsible for loss of power to an Interconnection Customer when the Utility AC Disconnect is opened.

10.3 Grid Services

Grid services, such as fast frequency response, are not currently contemplated during technical review of ESS or by this TSM. Interconnection reviews are unable to address the complexity of the distribution system, including electrification, and the overlay of potentially changing and complex aggregated market offerings. As use cases, standards, and market rules develop for these functions, this section will be updated.

10.4 Interconnection Application

MN DIP Exhibit B indicates that additional information in the application may be required, and that the Minnesota Technical Requirements shall be referenced when completing the application. For purposes of MN DIP Exhibit B, this section outlines the additional information required in the application.

The MN Exhibit B and one-line diagram submitted by an Interconnection Customer shall clearly define which configurations, as named in Section 10.11, are being applied for. A declaration, provided in the appendices and matching the configuration being applied for, shall be included in the interconnection application. When applying for multiple configurations, only configurations that do not conflict with each other will be approved. Along with stating the configuration number, and meeting other applicable interconnection application requirements, the following questions about the configuration’s operational characteristics shall be answered in MN DIP Exhibit B or in an attachment:

1) Is the energy storage system considered AC or DC-hybrid coupled?

2) Does energy storage export energy to the Area EPS?

3) What source or sources charge the energy storage (i.e. Area EPS, PV, diesel, etc.)?

4) Is a NEM-eligible generator part of the interconnection?
    a. Is the storage 100 % charged by a NEM-eligible generator?

5) Does the energy storage parallel[5] with the Area EPS or is it a stand-alone system when providing energy?

6) What is the process for changing operational modes ad service (such as TOU, peak shaving, backup, etc.) of the energy storage?
    a. Are the modes of operation settings for changing mode of operation or service(s) under a mode of operation accessible to the end user or can they be locked down?

7) For non-export, how does the system control output so that storage power is not exported to the Area EPS under normal conditions?

[5] For this document, parallel operation is defined as a device producing power while in grid connected mode.

10.5 Interconnection Reviews

All electrical sources, including storage, that operate in parallel with the Area EPS are required to have an interconnection review and an Interconnection Agreement to ensure safety, system reliability, and operational compatibility. For purposes of this section, a source is considered to be operating in parallel with the Area EPS when it is connected to the Area EPS and can supply energy to the Interconnection Customer simultaneously with the Area EPS Operator supply of energy. Any source operating in parallel to the Area EPS is required to have an Interconnection Agreement.

Any Energy Storage System not operating in parallel will require a technical review, but validated systems will not require an Interconnection Agreement. Interconnection Customers with stand-alone energy storage interconnections are not required to have an Interconnection Agreement with the Area EPS Operator if they are in compliance with NEC 702, obtain an appropriate safety inspection, and can provide verifiable proof that those systems are operated such that they cannot operate in parallel with the Area EPS. If the operating mode that prevents parallel operation is controlled by firmware, the selection of this mode must be inaccessible to the end user to be eligible for this provision.

When a storage system is installed in conjunction with a generation system, both may be reviewed at the same time and be included in one Interconnection Agreement[6]. When a storage system is installed after the generation system, the review level will be based upon the combination of the onsite generation rated capacity and the storage nameplate capacity for the selected operating mode[7] of the storage system. The operating modes mode and services shall be compliant to tariff requirements and will be part of the Interconnection Agreement requirements. Any change in the operating modes, or firmware or software updates to the energy storage control system which modifies the operating modes or service(s) of the ESS unit, may require another review of the facility interconnection and possibly mitigations. If a storage system is installed at the same time as a generation source, a combined review is to be encouraged as the total time and cost will be less than two separate reviews.

[6] Interconnections are reviewed based on the combined nameplate ratings of the sources that can actually be simultaneously supplied to the grid, such as two inverters. The ongoing operation capacity portion of the review is based on the actual simultaneous performance AC ratings. If the contribution of the energy storage to the total contribution is limited by programing or by some other on-site limiting element, the reduced ongoing capacity will be used for interconnection reviews.

[7] Operating Modes includes such requirements as charging the energy storage only from an on-site renewable energy source that is net-metered, non-export requirements, or stand-alone storage systems.

10.6 Telemetry and Control

Energy Storage Systems are subject to Section 9, Interoperability requirements. Whenever a paralleled energy storage system is located on the same site with a generation system, its AC rated nameplate capacity will be included with the onsite generation for determining whether or not telemetry and/or remote separation control are needed.[8] This applies regardless if all sources are installed at the same time or at separate times. The AC nameplate determination is also based upon the selected operating modes of the energy storage as stated at the time of installation. Change in operating modes that impact the ability of the energy storage system to adhere to the requirements may require additional review which may result in a change in the necessary telemetry functionality.

10.7 Inadvertent Export

Energy Storage Systems shall be subject to the same inadvertent export requirements as Section 8.4.

10.8 Metering

In addition to the TSM Section 11, the Tariff and program rules under which the ESS is applying shall be consulted for metering requirements. Metering requirements, including the need for a Production Meter, depend on the size as well as program rules and metering requirements by applied for configuration [9]. Section 10.11 details each configuration and their associated metering requirements. Various tariffs measure capacity (demand) and energy (kWh) separately in time intervals. Some tariffs apply time-of-use rates. Any meter upgrade that is required for directional measurement will employ the same methodology for export measurement as is required by the tariff for delivered power and will be read at the same intervals.

Protected load panels, such as those represented in Configuration 3a in Section 10.11.3.1, may require additional metering to properly account for load and generation energy.

10.9 Operational Mode Programming

The energy storage inverter's software programming will control the appropriate charging, discharge, and bypass of the energy storage system. For energy storage which parallels with the Area EPS, the inverter software programming

[8] Less than full nameplate will be considered if the added source is limited by programing or onsite equipment element rating.
[9] For example, at the time this document is published, NEM systems under 40 kW that are not part of Solar*Rewards or other incentive programs do not require a production meter. Program rules and tariffs may change over time and the Interconnection Customer should review the most recent revision of relevant documents at the time of the interconnection application.

must be inaccessible[10] to unqualified personnel. For energy storage inverters involved in a configuration that requires 100% NEM-eligible charging, the programming selected must be protected[11] from modification by unqualified personnel so only the inverter manufacturer or installer can make a change to an operating mode that can charge the energy storage from any non-NEM-eligible source. The means of achieving this shall be provided as part of the Interconnection Agreement and Interconnection Application. Other means of securing the settings may be mutually agreed upon on a case-by-case basis. The Area EPS Operator reserves the right to conduct an inspection to verify compliance at a later date if problems arise or indications of possible non-compliance are present. If the operating mode selection cannot be made inaccessible to unqualified personnel, the energy storage system must be reviewed under each available operating mode.

10.10 Enter Service

ESS are subject to the same enter service requirements in Section 7.1 as other DER when operating as a generation source. However, as ESS may also enter a charging mode upon return of service, some additional consideration must be given in order to prevent Area EPS overloading or instability.

If the ESS is capable, all recharging of ESS from the Area EPS should be delayed for a minimum of 10 minutes upon restoration of the Area EPS source. Once the ESS initiates recharging, it should institute a charging ramp rate from 0% to 100% over a period of time no shorter than 5 minutes, if capable.

10.11 Configurations Compliant with Tariffs

This section provides configuration requirements for compliance with different tariff rates. The principles outlined in this section apply for all sizes of energy storage systems and generation systems, though the details of system design are expected to differ based on the specifics of an installation. Table 6 provides a summary of the allowable configurations. Figure 1 at the end of this section provides a flow chart to aid in the decision of a configuration. Diagrams showing the general principles are attached in Appendix B and are considered part of these requirements. For all configurations, the Area EPS Operator reserves the right to conduct an inspection to verify compliance at a later date if problems arise or indications of possible non-compliance are present.

[10] Inaccessible may include locks or other physical security. Inaccessible and/or password protection must be restricted to the manufacturer/developer/ installer.

[11] Programing protection may be by means of password protection or other means of making access physically inaccessible to the customer. The mode selection must be inaccessible to the customer in order to review an application under a single configuration.

	AC Coupled Battery						DC Coupled Battery	
	1A	1B	1C	2A	2B	2C	3A	3B
Configuration^	*Standby Energy Storage Only*	*Energy Storage Operation in Parallel without Generation*	*Energy Storage Operation in Parallel with Self-Generation*	*Standby Energy Storage with NEM Eligible Renewable Generation*	*Parallel Energy Storage Charged 100% by NEM Eligible Renewable Generation*	*Parallel Energy Storage Operation Subject to Non-Export*	*Hybrid Inverter with a Second Load Meter****	*Hybrid Inverter with a Transfer Switch*
Interconnection Type	Customers without Generation or Storage in Parallel with Self-Generation			Net Energy Metering (NEM) and Solar*Rewards for qualifying facilities				
Pair with Renewable Energy	Yes or No			Yes				
Parallel Operation Allowed	No	Yes		No	Yes		Yes	
Interconnection Review Required	No^^ ^^^	Yes		No^^ ^^^	Yes		Yes for Parallel Operation. Otherwise No	
Battery Charging	Utility or Self-Generation			Utility or Generation	100% Renewable Generation	Utility or Generation	100% Renewable Generation if Exporting	
Battery Discharging	Standby System^^^	Non-Export*		Standby System^^^	Export of 100% Renewable Generation Only, Otherwise Non-Export*	Non-Export*	Export of 100% Renewable Generation Only, Otherwise Non-Export*	
Telemetry and Control	Determined by total Distributed Energy Resources (DER) as addressed in PUC Rules, Interconnection Requirements							
Production Meter	No			Solar*Rewards and any DER > 40 kW			Solar*Rewards and any DER > 40 kW	
Agreements	Attestation of Conformance to NEC Article 702^^^	Interconnection Agreement (IA), Attestation, Operation Mode to be Identified in IA**		Attestation of Conformance to NEC Article 702^^^	Interconnection Agreement, Attestation, Operation Mode to be Identified in IA**		Interconnection Agreement, Attestation, Operation Mode to be Identified in IA**	

*** Inadvertent Export Allowed per Settlement Guidance documents.**

**** Operating Mode needs to be identified and also include requirements as indicated above for battery charging and battery discharging. Such as - charging from on-site renewable energy source that is net metered, non-export requirements or stand-alone storage system.**

***** Second Load Meter required only if a production meter is installed.**

^ Configuration and Operating Modes must be locked-down so user cannot change. If no lock-down, all available modes must be reviewed, mitigated as needed, and documented in IA Exhibit D.

^^ Authority Having Jurisdiction inspection required. If a DER is installed at the same time as the battery, it must be reviewed.

^^^ If operating mode is not locked-down, a full review and Interconnection Agreement is required.

Table 6: Energy Storage System Configurations

10.11.1 Configuration No. 1a, 1b, and 1c- Stand-Alone Energy Storage and Energy Storage Associated with Non-Exporting DER Systems

This section provides the requirements for the interconnection of energy storage systems as a standby source or for operating in parallel with the Area EPS to provide the Interconnection Customer with desired services such as demand reduction. These requirements apply to non-renewable DER when existing self-generation is present.

Three storage configurations are achievable under this section:

- Standby Energy Storage Interconnections without Generation under NEC 702 (Diagram No. 1a)
- Energy Storage Operation in Parallel without Generation (Diagram No. 1b)
- Energy Storage Operation in Parallel with Non-Export Self-Generation[12] (Diagram No. 1c)

Each diagram provides the representative configuration in principle. Individual interconnection designs may have other features not reflected in the diagram, but the operational principle shall be consistent with the operational principle demonstrated by the diagram. The desired functionality may be controlled by inverter or control system programming.

Interconnection Customer s with stand-alone energy storage interconnections are not required to have an Interconnection Agreement with the Area EPS Operator if they are in compliance with NEC 702, obtain an appropriate safety inspection, and can provide verifiable proof that those systems are operated such that they cannot enter into parallel operation with the Area EPS. In order to be eligible for stand-alone energy storage interconnection, settings used to modify the operating mode such that the energy storage system parallels with the Area EPS must be inaccessible to unqualified personnel or end-user. Interconnection Customers with stand-alone energy storage interconnections are required to have an Interconnection Agreement when their system is operated in parallel with the Area EPS by serving their main electrical panel and/or protected load panel.

10.11.1.1 Standby Energy Storage Interconnections without Generation under NEC 702 (Diagram No. 1a)

NEC 702 provides for optional standby (i.e. backup) systems. Optional standby systems are intended to supply power to public or private facilities or property where life safety systems do not depend on the performance of the system. Optional standby systems are intended to supply on-site generated or stored power to selected loads, either automatically or manually. The generators or energy storage do not operate in parallel with the Area EPS. The energy storage may be charged from the Area

[12] Self-generation is a customer supplying part or their entire load from onsite generation with no intent of export or payment for export.

EPS but may not supply power to the Interconnection Customer's load outside of standby operations. The design is in conformance with the National Electric Code (NEC) Article 702 Optional Standby Power. This configuration is commonly used in conjunction with a protected load panel that is normally fed from the main panel and can be fed by the standby system when the Area EPS is unavailable.

If the above standby conditions are met, in order to be eligible for stand-alone energy storage interconnection, settings used to modify the operating mode such that the energy storage system will parallel with the Area EPS must be inaccessible to unqualified personnel or end-users.

10.11.1.2 Energy Storage Operation in Parallel without Generation (no export) (Diagram No. 1b)

If the Interconnection Customer has onsite energy storage operating in parallel with the Area EPS, meter registration will occur for exported power[13]. Subject to the Inadvertent Export provisions below, as a part of the interconnection review, the Interconnection Customer must provide the control system settings to ensure the power source does not export to the Area EPS.

Metering for this operating mode will use bi-directional meters. The bi-directional meters will register for power exported and will be used to check for compliance with inadvertent export requirements. At some future date, meters may be upgraded for increased functionality.[14] Where bi-directional measurement of delivery point power is used, both in and out quantities will be read with only the register for power serving the Interconnection Customer's facility used for billing purposes.

10.11.1.3 Energy Storage Operation in Parallel with Non-Export Self-Generation (Diagram No. 1c)

If the Interconnection Customer has onsite self-generation, meter registration will occur for exported power regardless of the source

[13] Exported power will be recorded in a non-billing register that will be used for verifying compliance with inadvertent export provisions..

[14] Meters may require upgrading due to changing metering standards, metering technology changes, or new system control installation.

providing the power[15]. Subject to the Inadvertent Export provisions below, as a part of the interconnection review, the Interconnection Customer must provide the control system settings to ensure the energy storage power source does not export to the Area EPS.

Metering for this operating mode will be bi-directional meters. The bi-directional meters will register for power exported which will be used to check for compliance with inadvertent export requirements. At some future date, standard service meters may be upgraded for increased functionality.[16] Where bi-directional measurement of delivery point power is used, both in and out quantities will be read with only the register for power serving the Interconnection Customer's facility used for billing purposes.

10.11.2 Configuration No. 2a, 2b, and 2c- Dedicated Inverter Energy Storage Configuration Coupled with NEM-Eligible Generation

This section provides the requirements for the interconnection of electric storage to operate in parallel with the Area EPS and an Interconnection Customer's NEM-eligible generation. The following configurations apply to systems which have separate inverters for the energy storage and onsite generation. The energy storage is connected between the Area EPS's Main Service Meter and Production Meter[17], when applicable, in a NEM arrangement.

This section addresses an energy storage system that is paired with a NEM-eligible generation, often in a NEM arrangement, to be operated in parallel with the Area EPS provided that (i) an interconnection review is completed; and either (ii) the storage system is charged exclusively by the NEM-eligible generation, or (iii) the Interconnection Customer can demonstrate the storage system will never export to the Area EPS.

There are three basic energy storage configurations that are permitted in this section. The second configuration has three alternative arrangements:

[15] Exported power will be recorded in a non-billing register that will be used for verifying compliance with inadvertent export provisions.
[16] Meters may require upgrading due to changing metering standards, metering technology changes, or new system control installation.
[17] Production meters requirements differ depending on specifics of the program and the size of generation proposed.

- Standby Energy Storage Operation Coupled with a NEM-Eligible Generation (Diagram No. 2a)
- Parallel Energy Storage Operation 100% Charged by a NEM-Eligible Generation (Diagram No. 2b)
- Parallel Energy Storage Operation Subject to No-export Restrictions (Diagram No. 2c)

Each diagram provides the representative configuration in principle. Individual interconnection designs may have other features not reflected in the diagram but the operational principle shall be consistent with the operational principle demonstrated by the diagram. The desired functionality may be controlled by inverter or control system programming.

Metering will be the same as standard service NEM.

10.11.2.1 <u>Standby Energy Storage Operation with a NEM-Eligible Generator (Diagram No. 2a)</u>

Standby batteries may charge from the onsite NEM-eligible generation or the Area EPS, but cannot discharge into the Interconnection Customer's main panel. Standby operation is applied to a protected load panel in a manner consistent with National Electric Code Article 702. See Section 10.11.1 for standby energy storage interconnection with non-NEM-eligible generation self-generation.

10.11.2.2 <u>Parallel Energy Storage Operation Charged 100% by NEM-Eligible Generation (Diagram No. 2b)</u>

This configuration allows energy storage systems that are 100% charged with onsite NEM-eligible generation to be connected in parallel to the Area EPS and to export to the Area EPS. If a Production Meter is present, the energy storage system can be connected on the Area EPS-side of the Production Meter with this configuration. A transfer switch is provided to divert NEM-eligible AC power to the energy storage for charging. This diversion of power may be accomplished internally with the inverter package either via a built-in switch or through inverter programming. The inverter's software programming will control the appropriate charging, discharge, and bypass of the energy storage system.

The inverter software programming must be inaccessible[18] and/or password protected.

This configuration shall use a separate energy storage inverter from the PV inverter.

10.11.2.3 Parallel Energy Storage Operation Subject to No-export Restrictions (Diagram No. 2c)

If the parallel energy storage can be charged by power from the Area EPS via the main panel and thus is not 100% charged from a NEM-eligible generator, the energy storage must not export to the Area EPS. Subject to the Inadvertent Export provisions below, the energy storage may not export power at the delivery point meter onto the Area EPS. Nothing in these requirements shall be construed to limit the export of actual onsite NEM-eligible self-generation that is net metered.

The Interconnection Customer is responsible for dynamically managing the energy storage operation so that these conditions are met regardless of the NEM-eligible DER's output and any variations in the NEM-eligible DER's output or the Interconnection Customer's load.

The no-export requirement does not allow compensation to be paid for exported energy storage power that is other than 100% renewable energy.

10.11.3 Configuration No. 3a and 3b – Hybrid Inverter Energy Storage Configuration Coupled with NEM-Eligible Generation

This section provides requirements for the interconnection of energy storage to operate in parallel with the Area EPS and an Interconnection Customer's NEM-eligible generation. The energy storage is connected to a hybrid inverter that serves both the energy storage and a NEM-eligible generation. The storage system must be charged exclusively by the onsite NEM-eligible generation in order to be eligible for exporting.

There are two basic energy storage configurations that are permitted under configuration #3. In the two configurations, the energy storage is assumed to be using a shared hybrid inverter along with the NEM-eligible

[18] Inaccessible may include locks or other physical security. Inaccessible and/or password protection must be restricted to the manufacturer/developer/ installer.

generation. These configurations would be necessary when a Production Meter is required.

- Hybrid Inverter and a NEM-Eligible Generation with a Second Load Meter (Diagram No. 3a)
- Hybrid Inverter and a NEM-Eligible Generation with a Transfer Switch (Diagram No. 3b).

Each diagram provides the representative configuration in principle. Individual interconnection designs may have other features not reflected in the diagram but the operational principle shall be consistent with the operational principle demonstrated by the diagram. The desired functionality may be controlled by inverter or control system programming.

There may also be a configuration without a protected load panel. This would be identical to Diagram No. 3b, but without a transfer switch or protected load panel.

For configuration 3b, metering will be the standard service meter for NEM. Large commercial and industrial Interconnection Customers will use bi-directional meters suitable for their rate class.

This configuration requires the energy storage to be 100% charged with renewable energy from the on-site NEM-eligible generation if the energy storage is capable of exporting energy. Energy storage systems that are not capable of exporting to the Area EPS do not have restrictions on the source of charging. The installation must be designed and programed to comply with this condition. For inverters, the programming selected must be protected[19] from modification so only the inverter manufacturer or installer can change the renewable only charging programming. The means of achieving this shall be provided as part of the Interconnection Agreement and Interconnection Application. Other means of securing the settings may be mutually agreed upon on a case-by-case basis.

[19] Inaccessible may include locks or other physical security. Inaccessible and/or password protection must be restricted to the manufacturer/developer/ installer.

10.11.3.1 Hybrid Inverter and NEM-Eligible Generation with a Second Load Meter (Diagram No. 3a)

When a Production Meter is required, and a protected load panel is installed with the hybrid inverter and supplied through that inverter, a second unidirectional Load Meter must be installed between the hybrid inverter and the protected load panel. The requirements for this, and payment for this, will be specified in the Operating Agreement attachment to the Interconnection Agreement. The main Production Meter will be a dual-register bi-directional meter. When interval data is used, the Production and service meter must be able to be synchronized for the same time intervals. These three meters will enable the derivation of NEM-eligible energy production and load energy usage. The inverter software programming must be inaccessible and/or password protected.[20]

10.11.3.2 Hybrid Inverter and NEM-Eligible Generation with a Transfer Switch (Diagram No. 3b)

If a Transfer Switch is used to supply the protected load panel from the Area EPS under normal conditions, no power will flow in reverse through the Production Meter, if applicable. This eliminates the need for the second load Meter. The required Main Metering and Production Metering, if applicable, will be the standard meters for NEM-eligible generation. At some future date, the meters may be upgraded to bi-directional meters[21]. The inverter software programming must be locked down and password protected.

[20] Inaccessible may include locks or other physical security. Inaccessible and/or password protection must be restricted to the manufacturer/developer/installer.
[21] Meters may require upgrading due to changing metering standards, metering technology changes, or new system control installation.

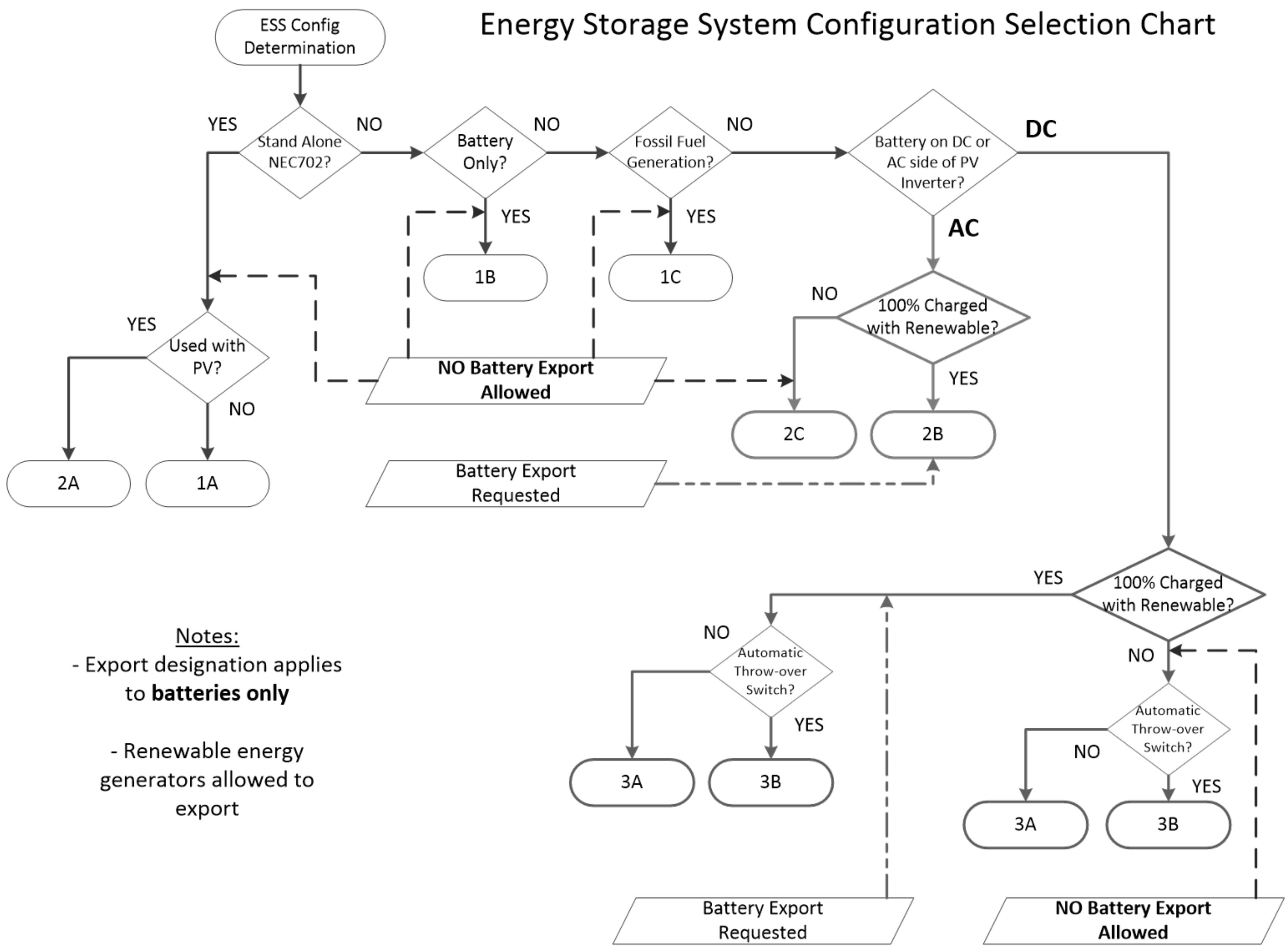


Figure 1: Energy Storage System Configuration Selection Chart

11 Metering Requirements

Metering equipment installation standards are driven by the needs to serve the entire Area EPS Operator customer base. As a result, many metering installation requirements are not specific to DER, and typical service requirements can be used. As all DER require electric service, the Standard for Electric Installation and Use document shall also be reviewed in conjunction with this TSM to ensure compliance with all Area EPS Operator service requirements for both electric service and DER interconnection. Many metering requirements are also driven by the Rate Schedule being applied for. Area EPS Operator's Section 9 and 10 Tariffs shall be referenced when designing the DER installation.

Where practical, the most relevant sections of the Standard for Electric Installation and Use are reproduced below, although the entire standard is applicable to all electric services that include DER. Any DER specific requirements not contained in the standard are included in this section. Should conflict exist between the TSM and Standard for Electric Installation and Use, the Standard for Electric Installation and Use shall be considered the controlling document. Area EPS Operator will make all efforts to keep both of these documents in sync with each other.

11.1 Provisions for Meter Installations

There are many different configurations possible for meter installation that are dependent on the voltage and service size of each DER installation. The Standard for Electric Installation and Use shall be used to determine meter and CT cabinet requirements.

11.2 Main Service Meter

The main meter is the meter located at the PCC, typically used for billing of customer energy usage. For DER under rate schedules that allow for excess energy to be sold back to the Area EPS Operator, a bi-directional meter may need to be installed. A bi-directional meter allows for power flow to be metered in both directions.

Interconnection Customers installing DER who are not eligible for sale of excess energy will require a detented meter. A detented meter will allow for power flow back to the Area EPS, but will not register power flow in the reverse direction as sale to the Area EPS.

All main service meter sockets and/or CT/PT compartments shall follow the requirements of the Standard for Electric Installation and Use.

Self-contained main service meter sockets shall have the generation source wired to the load side terminals of the self-contained meter socket. When instrument transformers are utilized for the main service meter, the H1 polarity marking shall be facing the Area EPS source.

11.3 Production Metering

Production meters are used for several scenarios. When an incentive is offered for production of electricity from a specific source, this production must be recorded before it is absorbed by the Interconnection Customer's local load. In another scenario, for large DER, it is often desirable to separate load from generation for purposes of planning the distribution system. To record only production, a production meter may be required. Below are the requirements for production metering.

1) A production meter is not required for systems rated under 40 kW AC, unless that system is subject to an incentive program rule requiring a production meter (e.g., Solar*Rewards), or otherwise allowed by rule or tariff. A production meter is required for all systems rated 40 kW AC or above. When required, the production meter will be Area EPS Operator-owned and supplied, but paid for by the Interconnection Customer unless otherwise specified by the tariff.

2) A single point of manual AC disconnect meeting the requirements of Section 6.1 shall be installed between the DER and the production meter, adjacent to the production meter.

3) Production Meter sockets and/or CT/PT compartments are subject to the same requirements as main service meters. Specific installation requirements based on the rating and voltage of the production meter can be found in the Standard for Electric Installation and use.

4) The production meter shall be located within ten feet of the existing billing meter. If this cannot be accomplished, additional labeling at each meter directing personnel to the other meter location is required.

5) Self-contained production meter sockets shall have the DER source wired to the line side terminals of the self-contained meter socket. When instrument transformers are utilized for the production meter, the H1 polarity marking shall be facing the Interconnection Customer DER source.

6) The production meter shall be labeled in accordance with the requirements of Section 4.14.3 of the Standard for Electric Installation and Use.

7) Production meters shall be installed at an Area EPS Operator standard voltage, as listed in Section 3.1.1 of Xcel Energy's Standard for Electric Installation and Use.

8) No loads or energy storage systems shall be connected on the DER side of the production meter.

11.3.1 Customer-Owned Production Meters

An Interconnection Customer may choose to have customer-owned production meters. This customer-owned metering will be in addition to the required Area EPS Operator-owned production metering. The customer-owned meter will need to be supplied and maintained by the Interconnection Customer. If this meter is in series with the Area EPS Operator-required production meter, there shall be a manual means of disconnect between the two production meters. Customer-owned production meters shall be located between the Area EPS Operator-owned production meter and the Main Service Meter.

11.4 Summary of Metering Requirements

Table 7 provides a summary of metering requirements. Depending upon which tariff the DER and/or Interconnection Customer's load is being supplied under, additional metering requirements may result. Contact Area EPS Operator for tariff rate requirements.

DER System Capacity at Point of Common Coupling	Metering
< 40 kW with all sales to Area EPS	Bi-Directional metering at the point of common coupling
< 40 kW with Sales to a party other than the Area EPS	Recording metering on the DER and a separate recording meter on the load
40 - 250kW with limited parallel	Detented Area EPS Metering at the Point of Common Coupling
40 - 250kW with extended parallel	Recording metering on the DER and a separate recording meter on the load
250 - 1000 kW with limited parallel	Detented Area EPS Metering at the Point of Common Coupling
250 - 1000 kW With extended parallel operation	Recording metering on the DER and a separate recording meter on the load.
>1000 kW With limited parallel Operation	Detented Area EPS Metering at the Point of Common Coupling
>1000 kW With extended parallel operation	Recording metering on the DER and a separate recording meter on the load.

Table 7: Metering requirements

12 Signage and Labeling

All signage and labelling shall be in accordance with NEC. In order to provide a safe operating environment for Area EPS Operator personnel, several additional labelling and signage requirements will need to be met. All installed signage and labeling required by the NEC and Area EPS Operator shall meet NEC 110.21 (B).

12.1 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.

12.2 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, ESS, Gas Generator). The sign shall provide clear direction to the distance and location of all DER Utility AC Disconnects. A map shall include outline of all structures in the area and compass arrow for orientation.

12.3 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.

13 Test and Verification Requirements

Per the interim adoption addendum Attachment 1, Section 14, Test and Verification Requirements of the TIIR are not applicable in the interim period. The Area EPS Operator’s TSM shall be used during this time. This section contains Test and Verification requirements comparable to Section 8 of the 2004 State of Minnesota Distributed Generation Interconnection Requirements. This section is largely unchanged from the 2004 requirements, but has been updated with language to reflect the current state of technology and associated definitions to more clearly convey the technical requirements contained herein.

13.1 UL 1741 Type-Tested Equipment

Minnesota Distributed Energy Resources Interconnection Process Attachment 5, Certification of Distributed Energy Resource Equipment, contains requirements for DER to be considered certified. In practice, this certification is recognized as UL 1741 for inverter-based DER. DER certified to UL 1741 will typically have fewer testing requirements than non-certified equipment. Currently, UL 1741 certification only applies to the inverter itself, but 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 behavior of the DER system to not be compliant with IEEE 1547-2003 if not carefully reviewed. Usage of UL 1741 certified inverters may only partially fulfill the complete installation’s compliance with IEEE 1547-2003. Additional protective relays or equipment settings changes may be required to achieve compliance. Manufacturer recommendations shall be followed, and for more complex installations where UL 1741 certified functionality is achieved through non-certified equipment, a professional engineer may need to be consulted to evaluate compliance with IEEE 1547-2003/IEEE1547a-2014. The usage of 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 Interconnection Customer to be interconnected to the Area EPS. An application will still need to be submitted and an interconnection review may still need to be performed, per MN DIP Sections 2.3 and 5.7, to determine the compatibility of the DER with the Area EPS.

Non-UL 1741 certified DER still must meet the requirements of IEEE 1547-2003, the TIIR, and the TSM. All devices used to achieve these requirements must be tested, and a report of the testing must be provided to Area EPS Operator upon request. For UL 1741 certified DER that use supplemental devices to achieve compliance with IEEE 1547-2003, the TIIR, and the TSM, these devices must also be tested, and a report of the testing must be provided to Area EPS Operator upon request. The Area EPS Operator may request to witness these tests on-site, per MN DIP Sections 2.3 and 5.7.

13.2 Commissioning Testing

The following tests shall be completed by the Interconnection Customer. All of the required tests in each section shall be completed prior to moving on to the next section of tests. The Area EPS Operator has the right to witness all field testing and to review all records prior to authorizing the system to operate in parallel, per MN DIP Sections 2.3, 5.7, and 5.8.

To prevent miscommunication or misinterpretation of testing results that could delay permission to operate, a representative of the Area EPS Operator is required to be present for testing. The Area EPS Operator shall be notified, with sufficient lead time to allow the opportunity for Area EPS Operator personnel to witness any or all of the testing. Three-phase DER sites typically require 8-10 weeks of lead time to schedule witness testing. Single-phase systems typically require 3 weeks of lead time to schedule witness testing. All witness test dates are subject to availability of Area EPS Operator personnel. Consult with the Interconnection Coordinator for more specific details about the expected lead time needed for scheduling a witness test.

13.2.1 Pre-Energized Testing

The following tests are required to be completed on the DER prior to energization by the Interconnection Customer. Only qualified personnel shall perform and sign-off on these tests. Written verification of each of these tests shall be made available to the Area EPS Operator upon request. It is recommended that a third party testing agency verify and certify test reports. Some of these tests may be completed in the factory if no additional wiring or connections were made to that component. These tests are marked with a “*”.

1) Grounding shall be verified to ensure that it complies with this standard, the NESC and the NEC.

   a) Verify that the equipment safety ground connections and other associated grounding equipment (i.e. grounding rods and grids) comply with the TIIR, TSM, NEC and NESC requirements.

   b) The Interconnection Customer shall provide a final factory nameplate drawing, as-built, of all ground referencing equipment 10 business days prior to the witness test. Updated calculations that show compliance with Section 7.5 of this standard shall be provided.

2) * CTs (Current Transformers) and VTs (Voltage Transformers) used for monitoring and protection shall be tested to ensure correct polarity, ratio and wiring and verified installed as indicated in Area EPS Operator approved design drawings.

3) CTs shall be visually inspected to ensure that all grounding and shorting connections have been removed where required.

4) Breaker / Switch tests - Verify that the breaker or switch cannot be operated with interlocks in place or that the breaker or switch cannot be operated remotely or automatically when in manual mode. Various DER Systems have different interlocks, local or manual modes, etc. The intent of this section is to ensure that the breaker or switches controls are operating properly.

5) * Relay Tests - All Protective relays shall be calibrated and tested to ensure the correct operation of the protective element. Documentation of all relay calibration tests and settings shall be provided to the Area EPS Operator upon request.

6) Trip Checks - Protective relaying shall be functionally tested to ensure the correct operation of the complete system. Functional testing requires that the complete system is operated by the injection of current and/or voltage to trigger the relay element and proving that the relay element trips the required breaker, lockout relay or provides the correct signal to the next control element. Trip circuits shall be proven through the entire scheme (including breaker trip). For inverters, a UL 1741 certification is adequate to satisfy the functional testing requirements of the internal inverter functions.

7) Remote Control, SCADA and Remote Monitoring tests - All remote control functions and remote monitoring points shall be verified operational. In some cases, it may not be possible to verify all of the analog values prior to energization. Where appropriate, those points may be verified during the energization process.

8) Phase Tests - the Interconnection Customer shall work with the Area EPS Operator to complete the phase test to ensure proper phase rotation of the DER and wiring. UL 1741 certified inverters that do not intentionally island are not required to perform this test.

9) Synchronizing test - The following tests shall be done across an open switch or racked out breaker:

   a) The switch or breaker shall be in a position that it is incapable of closing between the DER and the Area EPS for this test. This test shall demonstrate that at the moment of the paralleling-device closure, the frequency, voltage and phase angle are within the required ranges, stated in IEEE 1547-2003.

   b) A test shall also demonstrate that if any of the parameters are outside of the ranges stated, the paralleling-device shall not close.

   c) For UL 1741 certified inverter systems, this test may not be required unless the inverter creates fundamental voltages before the paralleling device is closed, such as in a micro-grid or intentional island.

13.2.2 Energized Commissioning Test

The following tests will proceed once the DER has completed Pre-Energized Testing and the results have been reviewed and approved by the Area EPS Operator. Updated as-built drawings, inverter settings, relay settings, grounding calculations, or any other applicable information shall be provided to the Area EPS Operator prior to the scheduled witness test. All energized commissioning tests shall be based on written test procedures agreed to between the Area EPS Operator and the Interconnection Customer. The location and method of measurement shall be listed for each step. The Interconnection Customer shall provide qualified personnel and supply proper equipment to adequately record the results of the tests.

The Energized Commissioning Test will require the following steps, at minimum:

1) Verification that 24/7 unescorted access is available to Area EPS Operator personnel

    a) Site access includes drivable and keyless access to all Area EPS Operator-owned equipment

2) Verification that the DER Installation matches the Area EPS Operator-approved as-built one-line diagrams

3) Verification that all required labelling meeting TSM Section 12 requirements is present

4) The Interconnection Customer shall verify that the settings and firmware for inverters, protective devices, power control systems, or other control hardware and software are in compliance with the TSM, TIIR, Operating and Maintenance Requirements attachment to the MN DIA, and match previously approved settings. Note: factory-provided default settings for other states or areas may not comply with MN requirements.

5) Any Remote Control, SCADA, or Remote Monitoring tests that could not be performed pre-energization shall be performed at this stage.

6) Anti-Islanding Test - For DER that parallel with the Area EPS for longer than 100msec, the following test steps shall be performed to verify compliance with IEEE 1547-2003. IEEE 1547.1-2005 shall be referenced for evaluation of acceptable testing procedures.

    a) The DER shall be started and connected in parallel with the Area EPS source.

        i) The steps required to energize the DER and parallel with the Area EPS shall be listed. This may include closing a number of disconnects and/or fuses.

        ii) Current, voltage, and power factor shall be verified.

        iii) For PV systems, this test needs to occur during the daytime with enough irradiance to produce at least 5% of each individual inverters’ nameplate kW rating. For sites that cannot achieve output greater than 15% of the DER nameplate rating, a fixed metering device such as an inverter display or customer-owned check meter shall be used for current verification so as to be able to determine the direction of power flow. When the output of the DER is greater than 15% of the nameplate rating, a handheld or portable meter to measure currents may be used. For multi-phase DER, the Interconnection Customer shall monitor all phases simultaneously.

b) The Area EPS source shall be removed by opening a device such as a switch, breaker, etc.

   i) The switching device shall be located such that all anti-islanding protective devices are tested simultaneously.

   ii) The switching device shall be located such that it is between the Area EPS source and any ground referencing equipment, if applicable.

   iii) For three-phase DER, this test shall be applied separately to all individual phases as well as all three phases simultaneously.

c) The DER shall either separate with the local load or stop generating within 2 seconds.

   i) Any voltages present on the DER side of the test point shall be verified as less than 110% of the nominal voltage.

d) The device that was opened to remove the Area EPS source shall be closed and the DER shall not re-parallel with the Area EPS for at least 5 minutes, or per a mutually agreed upon enter service time.

13.2.3 Final System Sign-off

To ensure the safety of the public, all DER systems greater than 250 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 State of Minnesota, prior to the installation being considered ready for commercial use. This certification shall be provided with the certified test report submitted to the Area EPS Operator in Section 5.7 of the TIIR.

13.2.4 Periodic Testing and Record Keeping

Any time the interface hardware, software, or firmware, including protective relaying and DER control systems are replaced and/or modified, the Area EPS Operator shall be notified. This notification shall, if possible, be with sufficient warning so that the Area EPS Operator personnel can be involved in the planning for the modification and/or witness the verification testing. Verification testing shall be completed on the replaced and/or modified equipment and systems. The involvement of the Area EPS Operator personnel will depend upon the complexity of the DER and the component being replaced and/or modified. Since the Interconnection Customer and the Area EPS Operator are now operating an interconnected system, it is important for each to communicate changes in operation, procedures and/or equipment to ensure the safety and reliability of the Local EPS and Area EPS.

All interconnection-related protection systems shall be periodically tested and maintained by the Interconnection Customer at intervals specified by the manufacturer or system integrator. These intervals shall not exceed 5 years. Periodic test reports and a log of inspections shall be maintained by the Interconnection Customer and made available to the Area EPS Operator upon request. The Area EPS Operator shall be notified prior to the period testing of the protective systems, so that Area EPS Operator personnel may witness the testing if so desired.

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

14 Sample Documents for Simplified Process

The following sections outline requirements for DER that qualify for the Simplified Process only, as described by the Minnesota Distributed Energy Resources Interconnection Process. Projects that do not qualify for the Simplified Process should contact the interconnection coordinator for document requirements.

14.1 One-line diagram

One-Line diagram, also known as a single-line diagram, showing the installation of the DER system and associated equipment shall be required with each interconnection application. An example of an acceptable one-line diagram is included at the end of this section. To reduce the chances of a delayed review by increasing the overall clarity of the one-line diagram, it is strongly recommended to use a standard graphical symbol set, such as that found in IEEE 315, when such a standardized symbol exists.

The following information shall be clearly depicted on the one-line diagram:

Contact information and General

1) Name of Interconnection Customer who owns/will own service, the Area EPS Operator "customer of record" for existing services.

2) Application OID or case number assigned to the project.

3) Clearly identify where test and verification features will be applied in the written test procedure as the Reference Point of Applicability or "RPA."

4) A note indicating that the design shall meet National Electric Code (NEC codes) requirements

Electrical Component Schematic

1) Label and show the electrical layout of all equipment in-line between the main service meter and the DER system.

2) The equipment listed shall include, at a minimum, switches, breakers, fuses, junction boxes, combiner boxes, protective devices, etc.

3) All customer equipment[22] shall be located on the customer-side of the main service meter.

4) Primary vs secondary interconnection shall be clearly noted and consistent with all other provided documentation.

5) Main service meter and main service panel.

6) Main service protection[23] between DER and the Area EPS.

7) The protective device shall be provided immediately after the main service meter.

8) Electrical ratings[24] of all equipment.

[22] Area EPS Operator Interconnection Facilities on the Area EPS Operator side of the PCC is not required to be shown on the customer one-line diagram. Any Area EPS Operator Interconnection Faciliites shown are subject to change and should not be used for planning/design purposes by the customer

[23] For DER being installed on existing buildings, the main service breaker will typically be sufficient

[24] Including, but not limited to, Volts, Amps, number of phases, kW, kVA, winding configurations

9) The aggregate AC capacity of each DER system.

10) The electrical ratings of the DER shall be provided:
    a. Voltage
    b. Power Output (KVA or kW)
    c. Phases (single or three-phase inverters)

11) Clearly note if inverter(s) are UL1741 certified.

12) *When multiple DER units are existing or proposed on a single service*: all DER systems shall be shown with proposed and existing marked.

13) *For energy storage systems*: the mode of operation, per Section 10.11, being applied for shall be clearly indicated on the one-line diagram.

14) The circuit for auxiliary equipment power necessary to the operation of the DER shall be shown

<u>Metering</u>

1) Production meter, if applicable, with ownership clearly noted (Area EPS Operator or customer).

2) Meter Phases
    a. For single-phase installations, the meter shall be specified as 1-phase, 3-wire.
    b. For three-phase installations, the meter shall be specified as 3-phase, 4-wire.

3) No loads or energy storage systems shall be connected on the DER side of the production meter.

4) All Area EPS Operator-owned production meters shall be installed at an Area EPS Operator standard voltage[25]
5) Production Meter CT polarity shall be shown on the drawing as facing the PV, i.e. H1 of the CT faces the inverter such that DER is seen by the production meter as kWh delivered.

[25] Xcel Energy standard service voltages can be found on Pg. 24, Section 3.1.1 of the Electric Standard for Electric Installation and Use. The inverter side of a step-up transformer may be a non-standard Area EPS Operator voltage, provided that no Area EPS Operator metering is located between the step-up transformer and the inverter

6) Customer owned meters shall not be located on the DER side of the Area EPS Operator production meter[26].

7) *For systems with an output of 200 amps or more:* any Area EPS Operator-owned metering requiring PTs shall be shown with the PTs unfused.

Utility AC Disconnect

1) A visible-open type, lockable, and readily accessible AC disconnect for purposes of isolating the DER from the Area EPS source labeled “Utility AC Disconnect,” “Photovoltaic Utility AC Disconnect,” or similar shall be shown.

2) Other AC Disconnects shall not be labeled or identified as a “Utility” AC Disconnect, if applicable.

3) If the Utility AC Disconnect is not located within 10 feet of the main service meter[27], a label meeting all requirements of the “Label Details” section shall be placed at the main service meter clearly showing the location of the Utility AC Disconnect.

4) For installations that require a Production Meter, the Utility AC Disconnect shall be located between the DER and production meter.

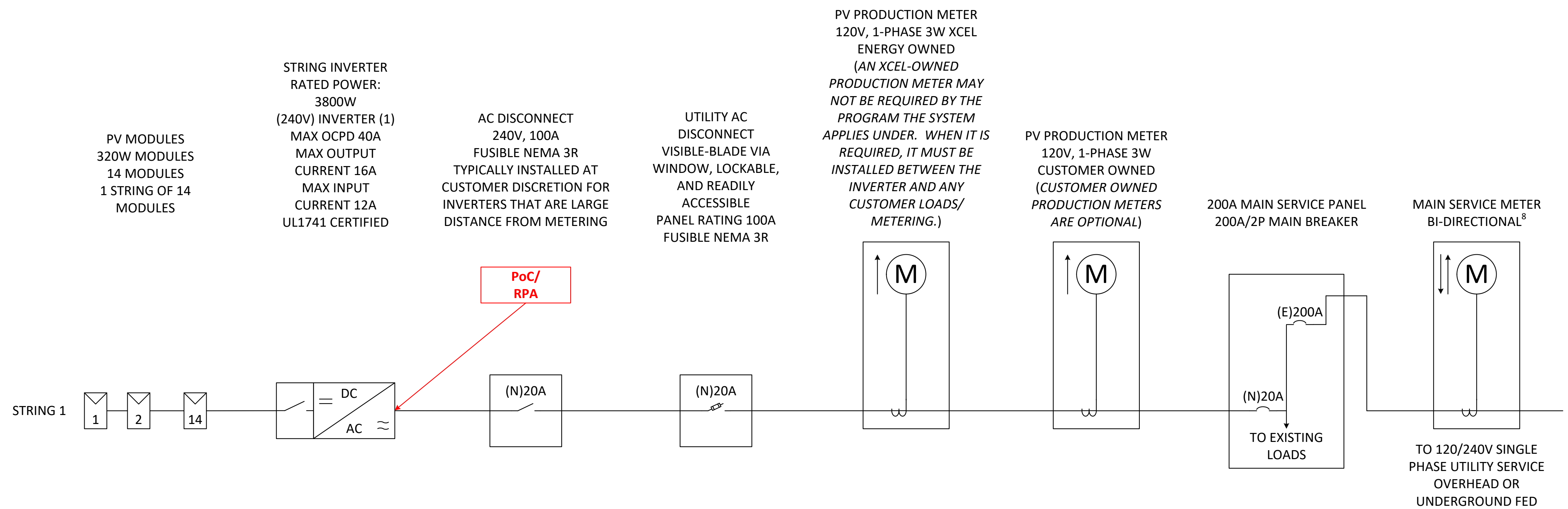
5) For installations not requiring a Production Meter, the Utility AC Disconnect shall be located between the DER and main service meter.

6) *When multiple DER units are existing or proposed on a single service:* if a single Utility AC Disconnect cannot be used to disconnect all DER, 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.

[26] Refer to applicable state interconnection tariffs and program rules to determine if production meters are applicable
[27] This will be evaluated as an exception, which may or may not be approved based on the accessibility of the AC Disconnect or the clarity of the placard

ONE LINE EXAMPLE A:

FOR SINGLE INVERTER SYSTEMS



	PV MODULE	INVERTER	UTILITY DISCONNECT	PV METER	MAIN SERVICE PANEL	INTERCONNECTION METHOD
Make:						
Model:						
Rating:						
Total:						

NOTES:

1. THIS DRAWING IS FOR ILLUSTRATIVE PURPOSES ONLY!
2. ALL TESTING SHALL BE PERFORMED BY QUALIFIED PERSONNEL, WITH PROPER PERSONAL PROTECTIVE EQUIPMENT
3. THE PRODUCTION METER AND AC DISCONNECT SHOULD BE LOCATED TOGETHER IN A READILY ACCESSIBLE LOCATION WITHIN 10' OF THE MAIN SERVICE METER
4. 24/7 UNESCORTED KEYLESS ACCESS SHALL BE PROVIDED FOR THE METERS AND AC DISCONNECT
5. UTILITY AC DISCONNECT SHOULD BE LOCATED WITHIN 10 FEET OF THE MAIN SERVICE METER
6. NOTE ALL THE APPLICABLE NEC CODES
7. SHOW ALL THE SYSTEMS INCLUDING STORAGE, EXISTING AND NEW (IF APPLICABLE)
8. SERVICES <320A WILL USE SELF-CONTAINED MAIN SERVICE METERS. 320A SERVICES MUST INDICATE WHETEHER THE METERING WILL BE SELF-CONTAINED OR TRANSFORMER METERED. ALL SERVICES 400A OR GREATER MUST BE TRANSFORMER METERED

PV SYSTEM:

ROOF SLOPE: 20°
AZIMUTH: 180°
PV MODULES: 320W
TOTAL: 14
MODULES PER STRING: 14

RACK CONFIGURATION:

INVERTER INFORMATION:

3.8KW UL CERTIFIED INTVERTER, (1)
DC/AC RATIO: 1.179

ABBREVIATIONS:

1. FOH: FRONT OF HOUSE
2. FSB: FIRE SET BACKS
3. (E): EXISTING
4. (N): NEW
5. PV: PHOTOVOLTAIC
6. MAX: MAXIMUM
7. OCPD: OVERCURRENT PROTECTION DEVICE
8. PCC: POINT OF COMMON COUPLING
9. PoC: POINT OF DER CONNECTION
10. RPA: REFERENCE POINT OF APPLICABILITY

SYSTEM SIZE:
3.8kW AC/4.48kW DC

CUSTOMER NAME
JOHN DOE

SCALE

PROJECT
EXAMPLE DRAWINGS FOR SMALL SOLAR INTERCONNECTIONS

INSTALLATION ADDRESS

INSTALLER NAME AND CONTACT

SHEET
ONE LINE DIAGRAM

SUBMITTAL
EXAMPLE

#	DATE	REVISION
1	12/1/2018	INITIAL SUBMITTAL
2	12/15/2018	UTILITY COMMENTS
3	6/17/2019	CORRECTED SUBMITTAL

APPLICATION OID, SRC, OR CASE NUMBER

PROFESSIONAL CERTIFICATION

DRAWN BY
JANE DOE

CHECKED BY
UTE I. LITTY

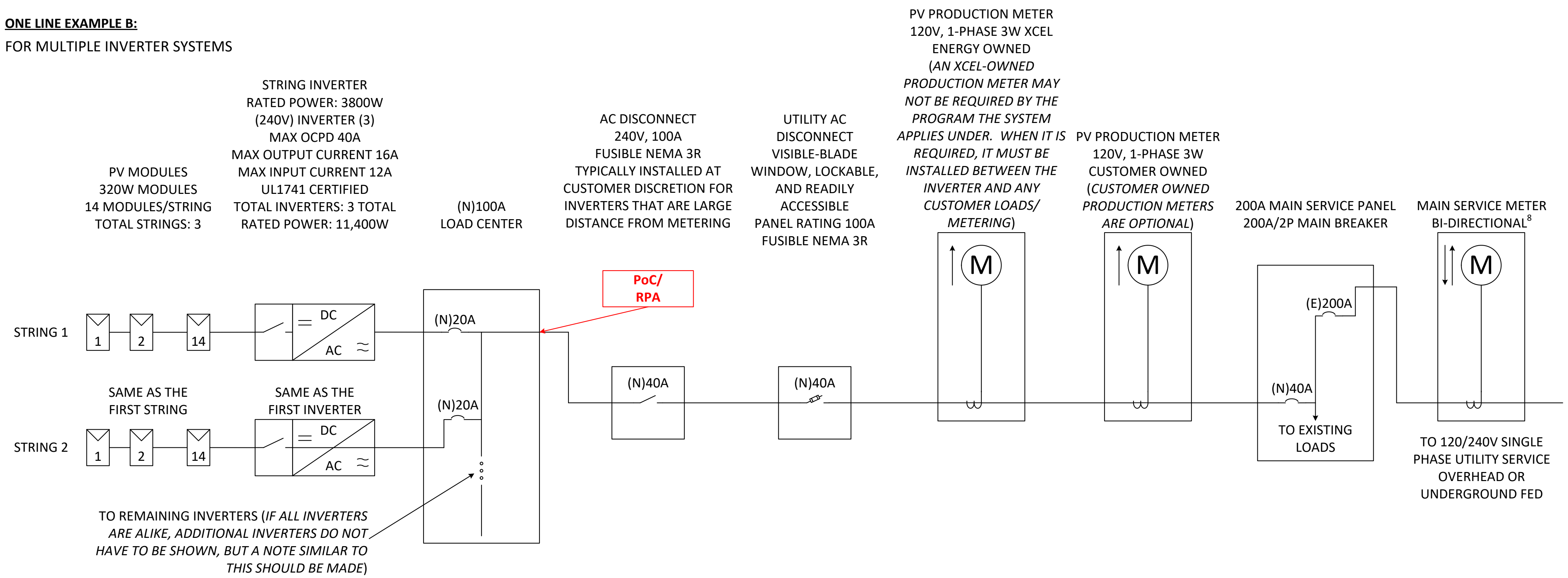
DATE
6/17/2019

PROJECT NUMBER
2019-100.01

SHEET NUMBER
E-101-02A

ONE LINE EXAMPLE B:

FOR MULTIPLE INVERTER SYSTEMS



	PV MODULE	INVERTER	UTILITY DISCONNECT	PV METER	MAIN SERVICE PANEL	INTERCONNECTION METHOD
Make:						
Model:						
Rating:						
Total:						

NOTES:

1. THIS DRAWING IS FOR ILLUSTRATIVE PURPOSES ONLY!
2. ALL TESTING SHALL BE PERFORMED BY QUALIFIED PERSONNEL, WITH PROPER PERSONAL PROTECTIVE EQUIPMENT
3. THE PRODUCTION METER AND AC DISCONNECT SHOULD BE LOCATED TOGETHER IN A READILY ACCESSIBLE LOCATION WITHIN 10' OF THE MAIN SERVICE METER
4. 24/7 UNESCORTED KEYLESS ACCESS SHALL BE PROVIDED FOR THE METERS AND AC DISCONNECT
5. UTILITY AC DISCONNECT SHOULD BE LOCATED WITHIN 10 FEET OF THE MAIN SERVICE METER
6. NOTE ALL THE APPLICABLE NEC CODES
7. SHOW ALL THE SYSTEMS INCLUDING STORAGE, EXISTING AND NEW (IF APPLICABLE)
8. SERVICES <320A WILL USE SELF-CONTAINED MAIN SERVICE METERS. 320A SERVICES MUST INDICATE WHETEHER THE METERING WILL BE SELF-CONTAINED OR TRANSFORMER METERED. ALL SERVICES 400A OR GREATER MUST BE TRANSFORMER METERED

PV SYSTEM:

ROOF SLOPE: 20°
AZIMUTH: 180°
PV MODULES: 320W
TOTAL: 32
MODULES PER STRING: 14

RACK CONFIGURATION:

INVERTER INFORMATION:

3.8KW UL CERTIFIED INTVERTER, (3)
DC/AC RATIO: 1.179

ABBREVIATIONS:

1. FOH: FRONT OF HOUSE
2. FSB: FIRE SET BACKS
3. (E): EXISTING
4. (N): NEW
5. PV: PHOTOVOLTAIC
6. MAX: MAXIMUM
7. OCPD: OVERCURRENT PROTECTION DEVICE
8. PCC: POINT OF COMMON COUPLING
9. PoC: POINT OF DER CONNECTION
10. RPA: REFERENCE POINT OF APPLICABILITY

SYSTEM SIZE:
11.4kW AC/13.44kW DC

CUSTOMER NAME
JOHN DOE

SCALE

PROJECT
EXAMPLE DRAWINGS FOR SMALL SOLAR INTERCONNECTIONS

INSTALLATION ADDRESS

INSTALLER NAME AND CONTACT

SHEET
ONE LINE DIAGRAM

SUBMITTAL
EXAMPLE

#	DATE	REVISION
1	12/1/2018	INITIAL SUBMITTAL
2	12/15/2018	UTILITY COMMENTS
3	6/17/2019	CORRECTED SUBMITTAL

APPLICATION OID, SRC, OR CASE NUMBER

PROFESSIONAL CERTIFICATION

DRAWN BY
JANE DOE

CHECKED BY
UTE I. LITTY

DATE
6/17/2019

PROJECT NUMBER
2019-100.01

SHEET NUMBER
E-101-02B

14.2 Site diagram

Site Plan or location plan identifying location of equipment noted on the one-line diagram shall show the following information:

Contact Information and General

1) Name of Customer who owns/will own the service, the Area EPS Operator "customer of record" for existing services.

2) Installation premise address.

3) Installation address shall match application address.

4) Installation address shall match the premise address for existing customer/services.

5) Installer name & contact information.

6) Application OID or case number assigned to the project.

7) Building(s) and streets shall be labelled.

8) A minimum of one street shall be included on the site plan, with the name, distance, and direction to the nearest cross street, if the nearest cross street is not shown.

9) Compass direction (indicate North).

Electrical Component Locations

1) Main service entrance, all meter locations, disconnects, transformers, proposed and existing DER systems.
    a. Distance shall be noted between this equipment.
    b. Primary vs secondary interconnection shall be clearly noted and consistent with all other documentation.

2) The Production Meter and Utility AC Disconnect shall be located together in a readily accessible location within 10' of the main service meter.

a. If the Utility AC Disconnect or Production Meter is not located within 10 feet of the main service meter[28], a label meeting all requirements of the "Label Details" section shall be placed at the main service meter clearly showing the location of the Utility AC Disconnect.

3) 24/7 unescorted keyless access shall be provided to all Area EPS Operator equipment.

4) Position, distance and clearance concerns of overhead electric service lines and/or other utilities in relation to the PV panels shall be noted.

5) A separate Detail View or Plan View may be required to clearly show location of meters, main service and Utility AC disconnect, when the site layout is unclear or illegible when printed on an 11"x17" sheet.

.

[28] This will be evaluated as an exception, which may or may not be approved based on the accessibility of the Utility AC Disconnect or the clarity of the placard

NOTES:

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

PV SYSTEM:

ROOF SLOPE: 20°
AZIMUTH: 180°
PV MODULES: 320W
TOTAL: 14
MODULES PER STRING: 14

RACK CONFIGURATION:

INVERTER INFORMATION:

3.8 KW UL CERTIFIED INTVERTER, (1)
DC/AC RATIO: 1.179

ABBREVIATIONS:

1. FOH: FRONT OF HOUSE
2. FSB: FIRE SET BACKS
3. (E): EXISTING
4. (N): NEW
5. PV: PHOTOVOLTAIC
6. MAX: MAXIMUM
7. OCPD: OVERCURRENT PROTECTION DEVICE
8. PCC: POINT OF COMMON COUPLING
9. PoC: POINT OF DER CONNECTION
10. RPA: REFERENCE POINT OF APPLICABILITY

SYSTEM SIZE:
3.8kW AC/4.48kW DC

CUSTOMER NAME
JOHN DOE

SCALE

0 10 20
SCALE IN FEET

PROJECT
EXAMPLE DRAWINGS FOR SMALL SOLAR INTERCONNECTIONS
INSTALLATION ADDRESS

INSTALLER NAME AND CONTACT

SHEET
SITE PLAN
SUBMITTAL
EXAMPLE

#	DATE	REVISION
1	12/1/2018	INITIAL SUBMITTAL
2	12/15/2018	UTILITY COMMENTS
3	6/17/2019	CORRECTED SUBMITTAL

APPLICATION OID, SRC, OR CASE NUMBER

PROFESSIONAL CERTIFICATION

DRAWN BY	**CHECKED BY**
JANE DOE	UTE I. LITTY
DATE	**PROJECT NUMBER**
6/17/2019	2019-100.01

SHEET NUMBER
E-101-01A

14.3 Test Procedure

A test procedure that will be used to verify the DER to Area EPS interface protection and operation of the DER system shall be submitted to the Area EPS Operator for approval. The procedure shall include an open phase test (for three phase systems) and an unintentional island detection test (for all systems) to verify the system ceases generating in parallel with the Area EPS Operator distribution system when the Area EPS source is lost. Although an example Test Procedure is provided here, each system is unique and will require a custom test procedure based on the DER[29]. In addition to the manufacturer's recommendations, the following steps or notes shall be included:

<u>Contact Info and General</u>

1) Name of Customer who owns service, the Area EPS Operator "customer of record" for existing services.

2) Installation premise address shall match application address.
   a. Address shall match the premise address for existing customer/services.

3) Application OID, SRC, or case number assigned to the project.

4) A note stating "All testing shall be performed by qualified personnel."

<u>Testing Applicable to all DER</u>

1) The procedure shall provide steps to verify fixed power factor settings for each inverter meet the project requirements.

2) The unintentional islanding test shall at minimum contain the following steps:
   a. Steps that verify DER system is ready to be energized.
   b. Steps to verify labeling for the Main Service Panel, DER Protection, DC Disconnect, AC disconnect, Utility AC Disconnect, Production Meter (when applicable) and other relevant labelling and signage
   c. Steps to energize the DER system.
   d. While in normal operation, steps to verify the voltages at the DER AC terminals are within 5% of the combined DER AC voltage ratings and all LEDs, alarms, and/or LCD codes are "normal."

[29] DER Owners may wish to consult with the Manufacturer regarding considerations specific the DER unit of interest.

e. While in normal operation, steps to verify that all DER units are operational and producing power.
f. Steps to simulate the loss of Area EPS source[30] for the unintentional islanding test shall be listed.
    i. Clearly identify the disconnection device being used to simulate this Area EPS power outage.
g. Using a voltmeter, verify the voltage at the inverter-side of the Utility AC Disconnect has dropped to zero.
    ii. Only customer-owned equipment shall be used for this verification. Area EPS Operator will not provide special equipment for this verification. Area EPS Operator provided meters shall not be used for this verification.
h. Using an ammeter or the DER's display/metering, verify the DER has ceased to energize within two seconds. For three phase systems, three phase monitoring may be required.

3) Verify DER LEDs, alarms, and/or LCD codes are appropriate for loss of Area EPS source.

4) Steps to restore the lost Area EPS source shall be listed.

5) A step to verify that the inverter system delays five (5) minutes before resuming power output after the Area EPS source is restored shall be listed.

Testing Applicable only to Three-Phase systems

1) For three-phase systems, steps to simulate an open phase condition from the Area EPS shall be included. The device used to create an open phase shall be clearly identified in the procedure.
    a. If ground referencing equipment is present, the open point must occur upstream of this device (upstream meaning in the direction of the Area EPS source).
    b. If the protection scheme used to detect the open phase uses devices other than the inverter (for instance, separate relaying to trip a recloser or breaker), the installer must provide an engineering analysis that demonstrates a non-detection zone does not exist when the output of the DER is 5% or greater of the aggregate inverter AC nameplate rating in the open phase detection schemes. A step will be required to

[30] This typically involves opening an AC disconnect.

disable this setting during testing if an acceptable engineering analysis cannot be provided.

2) Steps to verify voltage and current are to be listed for the open phase test. Location of measurement points shall be identified.

WITNESS TEST PROCEDURE

Example Only- Test procedures shall be unique to the equipment and customer

Customer: John J. J. Schmidt
Address: 123 Main St., Anytown, MN
Case #: 012345678

The following steps will be performed to verify the correct installation and anti-islanding functionality of the DER. The steps in this procedure shall be followed as they are presented. All testing shall be performed by qualified personnel.

I. Verify the system is ready to be energized:

1. Label Verification
    a. Check all required labelling is present: ___
        i. Main Service Panel: ___
        ii. Production Meter: ___
        iii. Utility AC Disconnect: ___
        iv. DC Disconnect:___
2. Construction Verification
    a. Perform a site walk-through, verifying system as-built matches utility-approved one-line diagram and site plan: ___
3. Confirm all wiring and construction is complete, and that the AHJ has approved the installation: ___

II. Once the above steps are complete, the system is ready to be energized. Proceed to the next steps

1. Close the back feed PV system circuit breaker in the Main Service Panel
2. Close the PV System AC disconnects in Subpanel A
3. Close the DER Utility AC Disconnect
4. Verify voltages at the Utility AC Disconnect are within 5% of the combined DER AC voltage ratings: ___
5. Verify LEDs indicating initialization: ___
6. Verify LCD message indicating Area EPS connect time: ___
7. Verify that all inverters are operational:___
    a. Using the inverter management application software, select “Inverter Status” from the main menu to display inverter operational status.
8. Verify that all inverters are producing at least 15% of their rated AC output:___

   a. Using the inverter management application software, select “Inverter Status” from the main menu to display individual inverter output.
9. Verify that all inverters are operating at 0.98 absorbing Power Factor:
   a. From the inverter interface, select “PF”
   b. Verify “PF” is set to “0.98 absorbing”:___

III. The DER system is now ready for simulation of loss of utility

1. Verify that all measurement instruments are in place at the Utility AC Disconnect (RPA, as indicated on the one-line diagram)
2. Open the disconnect labelled “Utility AC Disconnect” to simulate the loss of utility
3. Verify both voltage and current dropped to zero within two seconds, using a volt meter and ammeter
4. Verify all LEDs, alarms, and LCD codes indicate loss of utility

IV. The DER system is now ready to be re-energized

1. Close the disconnect labelled “Utility AC Disconnect”
2. Continue monitoring the current at the Utility AC Disconnect. Current should read zero amps for at least 5 minutes after disconnect is closed. Record time for inverters to begin generating.
   a. Time for inverters to begin generating: ___ min

I certify that the test procedure has been conducted according to the steps above, and that the tests verified successful operation of the DER system in accordance with the Minnesota Technical Interconnection and Interoperability Requirements and the Area EPS Operator Technical Specifications Manual.

Print Name and Title: ____

Signature: ____ Date: _______________

Appendix A- Types of Interconnections

A. Types of Interconnections

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

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

A.1 Open Transition (Break-Before-Make)

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

To qualify as an Open Transition switch and be subject to only the limited protective requirements, mechanical interlocks are required between the two source contacts. This is required to ensure that one of the contacts is always open and the DER is never operated in parallel with the Area EPS. If the mechanical interlock is not present, the protection requirements are as if the switch is a closed transition switch.

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

Figure 1 at the end of this Appendix provides a typical one-line diagram of this type of installation.

A.2 Quick Open Transition (Break-Before-Make)

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

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

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

Figure 2 at the end of this Appendix provides a typical one-line diagram of this type of installation and shows the required protective elements.

A.3 Closed Transition (Make-Before-Break)

The DER is synchronized with the Area EPS prior to the transfer occurring. The transfer switch then parallels with the Area EPS for a short time (100 ms or less) and then the DER and load is disconnected from the Area EPS. This transfer is less disruptive than the Quick Open Transition because it allows the DER a brief time to pick up the load before the support of the Area EPS is lost. With this type of transfer, the load is always being supplied by the Area EPS or the DER.

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

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

A.4 Soft Loading Transfer Switch

<u>With Limited Parallel Operation</u> - The DER is paralleled with the Area EPS for a limited amount of time (generally less than 1-2 minutes) to gradually transfer the load from the Area EPS to the DER. This minimizes the voltage and frequency problems, by softly loading and unloading the DER.

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

b) Protective Relaying is required as described in Section 6.

c) Figure 3 at the end of this Appendix provide typical one-line diagrams of this type of installation and show the required protective elements.

d) When paralleled for more than 100ms, electrical equipment shall be rated for the combined fault current of the Area EPS and DER contributions. Locations with dual Area EPS feeds can have significantly higher Area EPS fault current contribution.

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

a) Any anticipated use in the extended parallel mode requires special agreements and special protection coordination.

b) Protective Relaying is required as described in Section 6.

c) Figure 4 at the end of this Appendix provides a typical one-line diagram for this type of interconnection. It must be emphasized that this represents typical installations only and final installations may vary from the examples shown due to transformer connections, breaker configuration, etc.

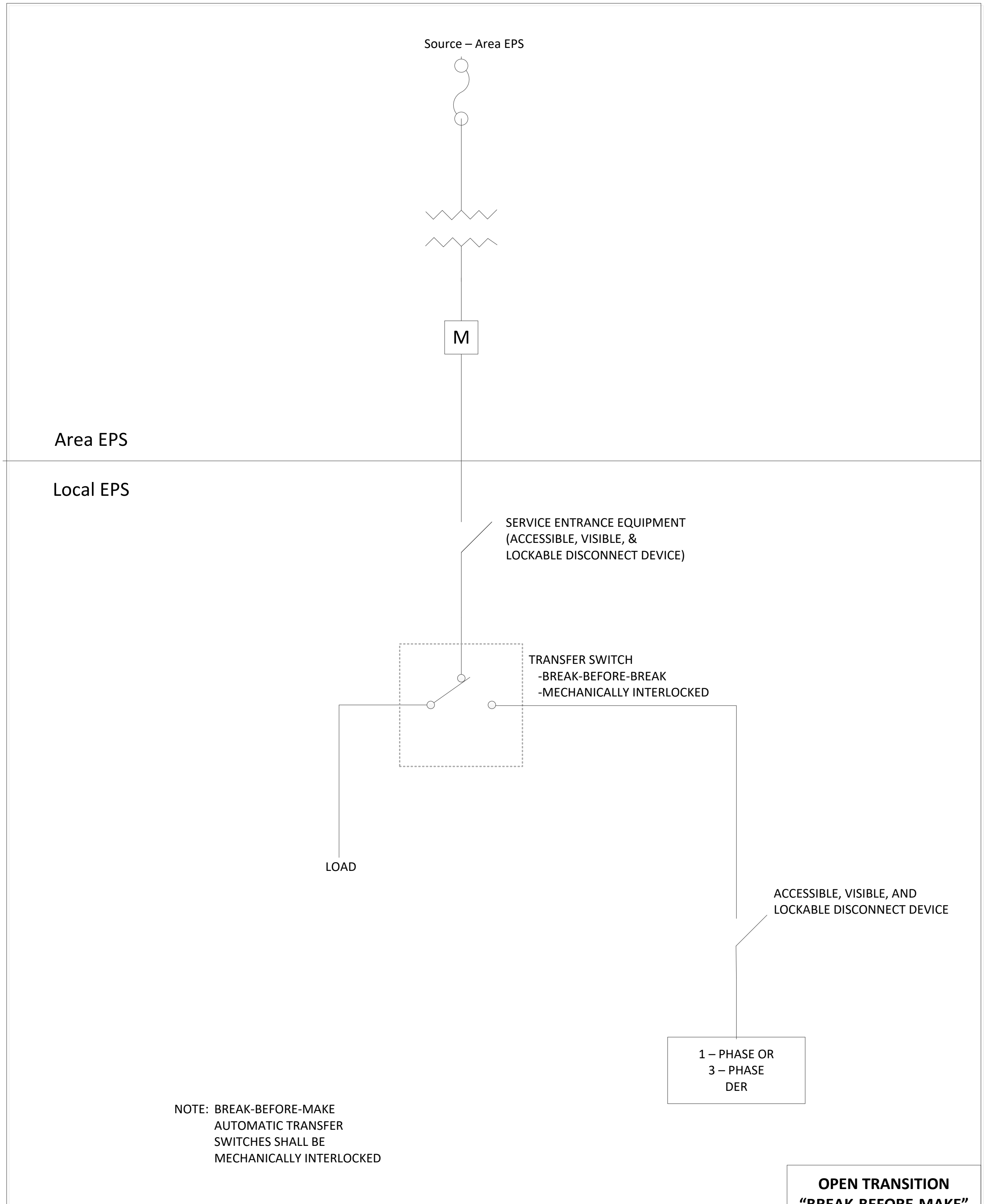
A.5 Inverter Connection

This is a continuous parallel connection with the system. Small DER may utilize inverters to interface to the Area EPS. Solar, wind, and energy storage are some examples of DER which typically use inverters to connect to the Area EPS. The design of such inverters shall either contain all necessary protection to prevent unintentional islanding, or the Interconnection Customer shall install conventional protection to affect the same protection. All required protective elements for a soft-loading transfer switch apply to an inverter connection. Figure 5 at the end of this Appendix shows a typical inverter interconnection.

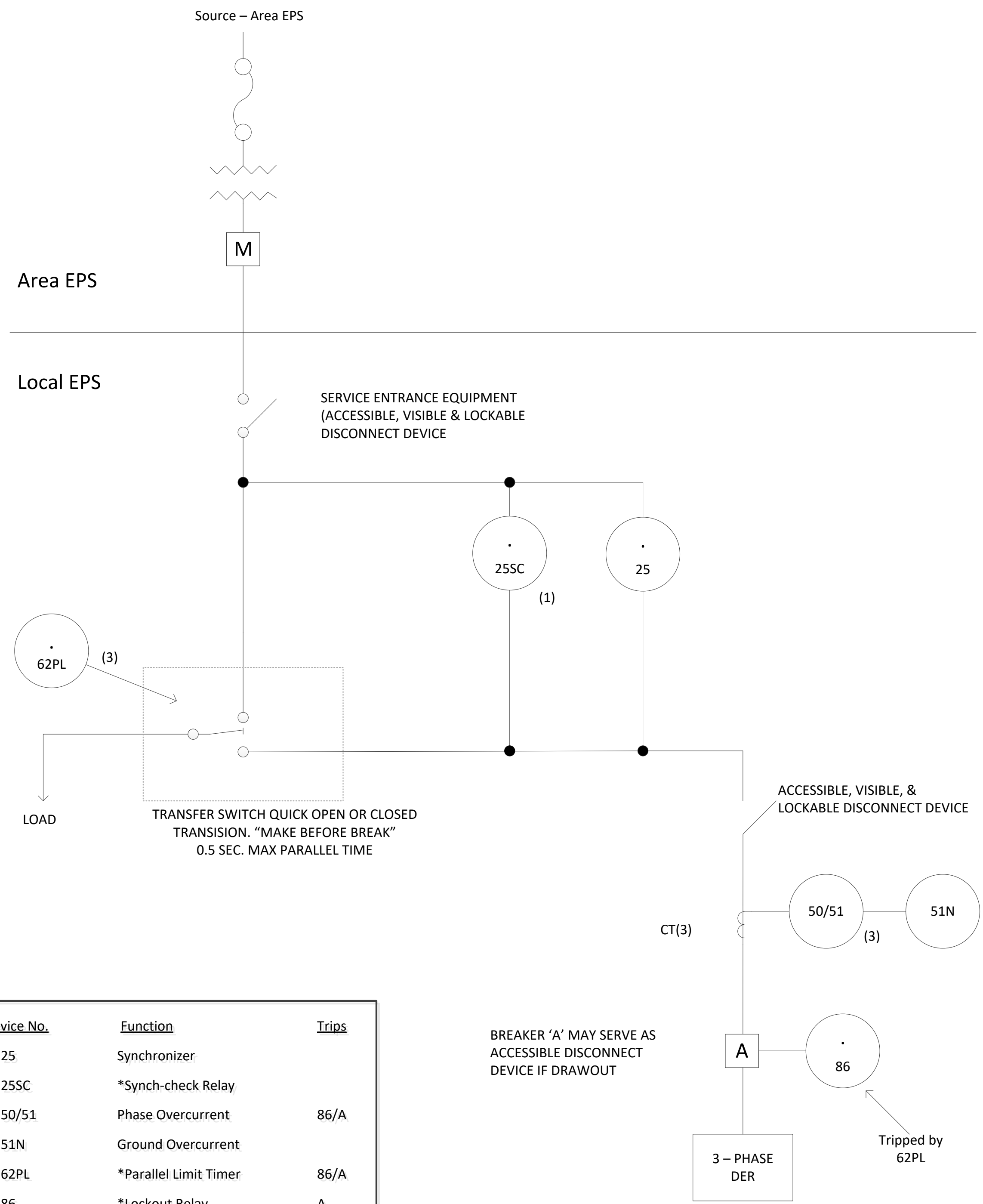
Prior to installation, the inverter shall be UL 1741 certified for interconnection to the electrical power system. The certification will confirm its anti-islanding protection and power quality related levels at the Point of Common Coupling. Also, Area EPS compatibility, electric shock hazard and fire safety are approved through UL listing of the model.

For three-phase operation, the inverter control must also be able to detect and separate for the loss of one phase. Larger inverters will still require custom protection settings, which must be calculated and designed to be compatible with the specific Area EPS being interconnected with.

A Utility AC Disconnect, as described in TSM Section 6.1 is required for safely isolating the DER when connecting with an inverter. The inverter shall not be used as a safety isolation device.



OPEN TRANSITION “BREAK-BEFORE-MAKE”	
DATE: April 2020	**Figure 1**



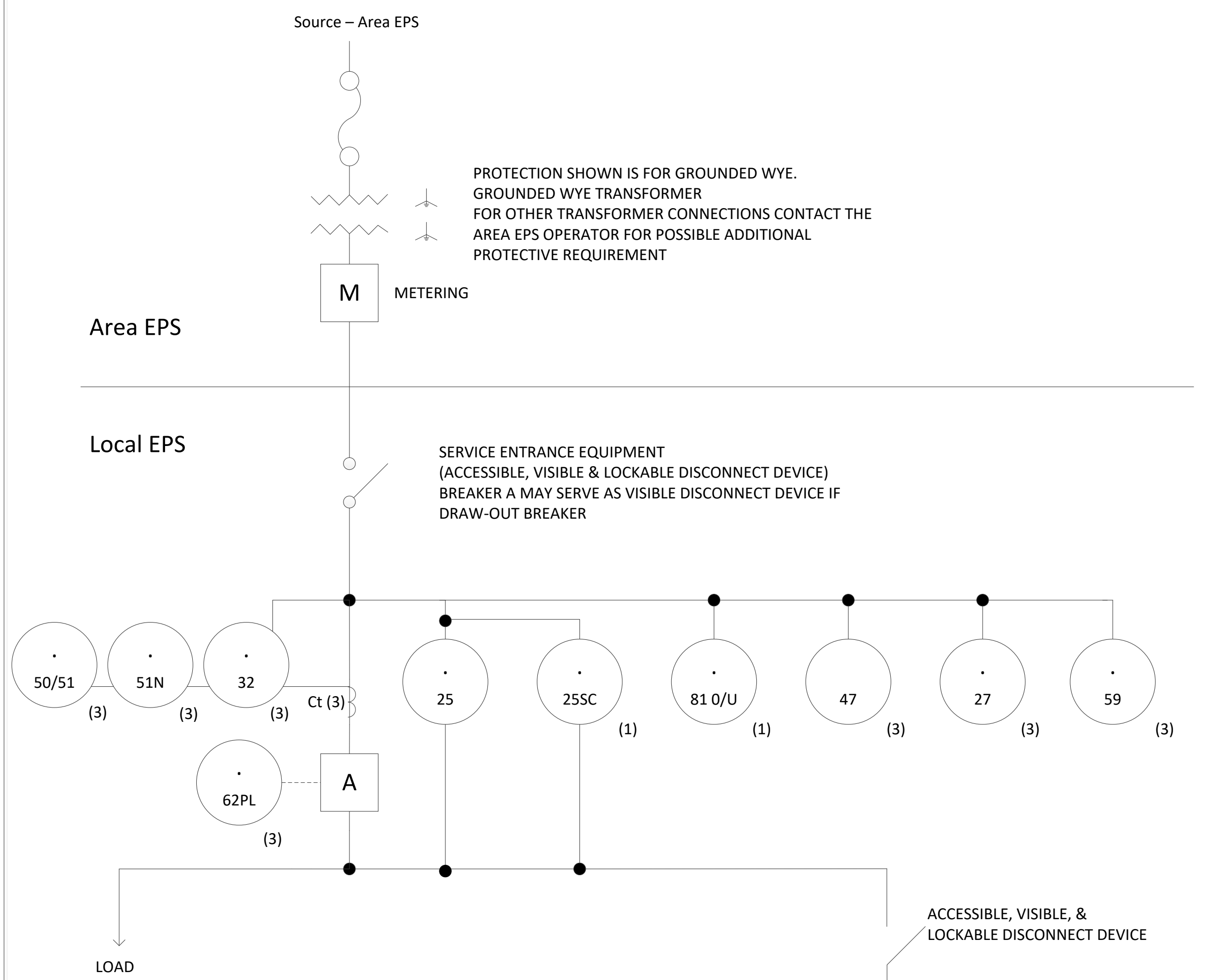
Device No.	Function	Trips
25	Synchronizer	
25SC	*Synch-check Relay	
50/51	Phase Overcurrent	86/A
51N	Ground Overcurrent	
62PL	*Parallel Limit Timer	86/A
86	*Lockout Relay	A

(1)(2)(3) Indicates Number of Phases to be Monitored

*Indicates Minimum Required Protection
Other Relays Shown are Recommended for Generator Protection

QUICK OPEN OR CLOSED TRANSITION "MAKE-BEFORE-BREAK"

DATE: April 2020	**Figure 2**

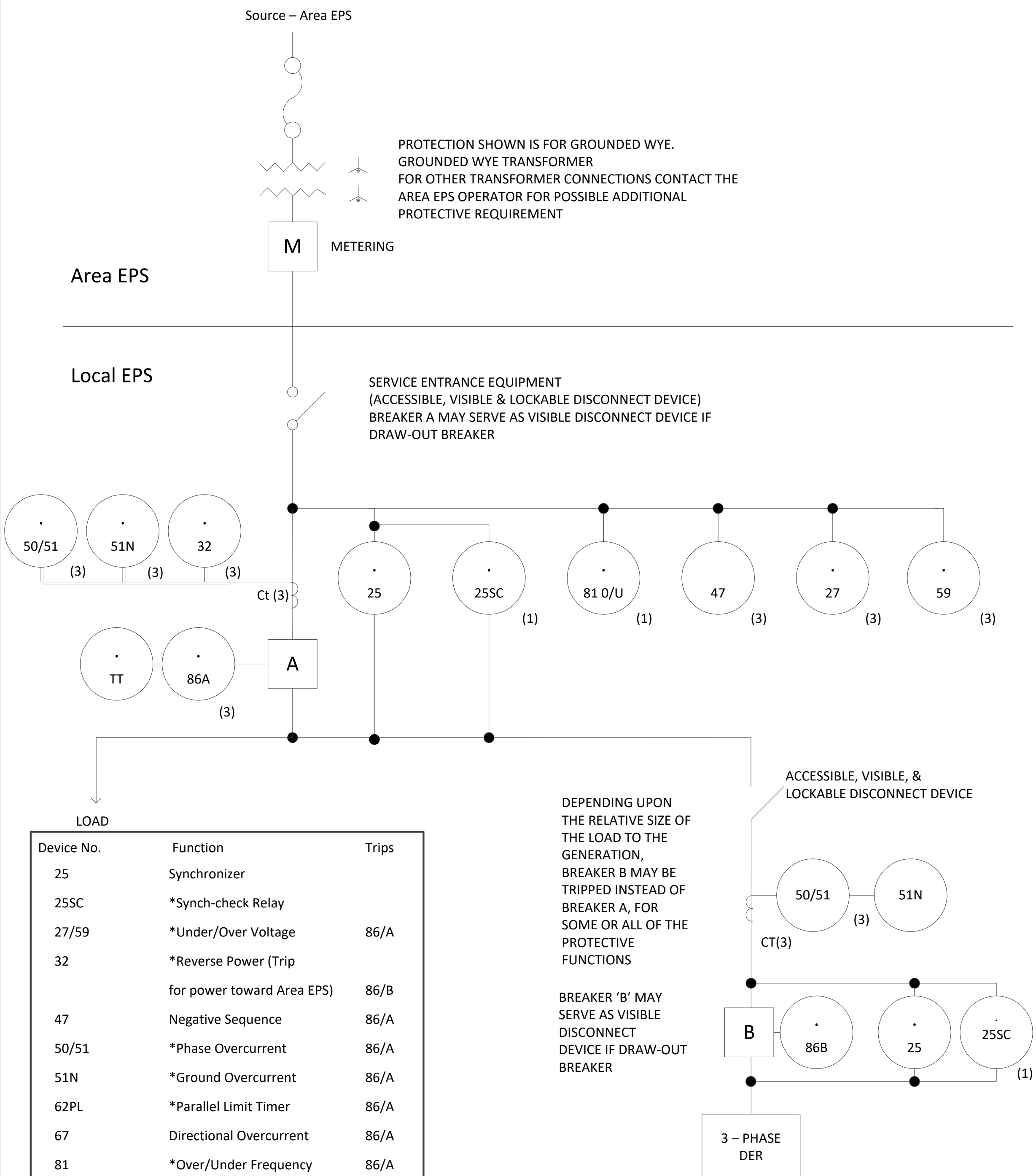


Device No.	Function	Trips
25	Synchronizer	
25SC	*Synch-check Relay	
27/59	*Under/Over Voltage	86/B
35	*Reverse Power (Trip	
	for power toward Utility)	86/B
47	Negative Sequence	86/B
50/51	*Phase Overcurrent	86/B
51N	*Ground Overcurrent	86/B
62PL	*Parallel Limit Timer	86/B
81	*Over/Under Frequency	86/B
86	*Lockout Relay	B

(1)(2)(3) Indicates Number of Phases to be Monitored

*Indicates Minimum Required Protection
Other Relays Shown are Recommended for Generator Protection

SOFT LOADING TRANSFER LIMITED PARALLEL OPERATION	
DATE: April 2020	Figure 3



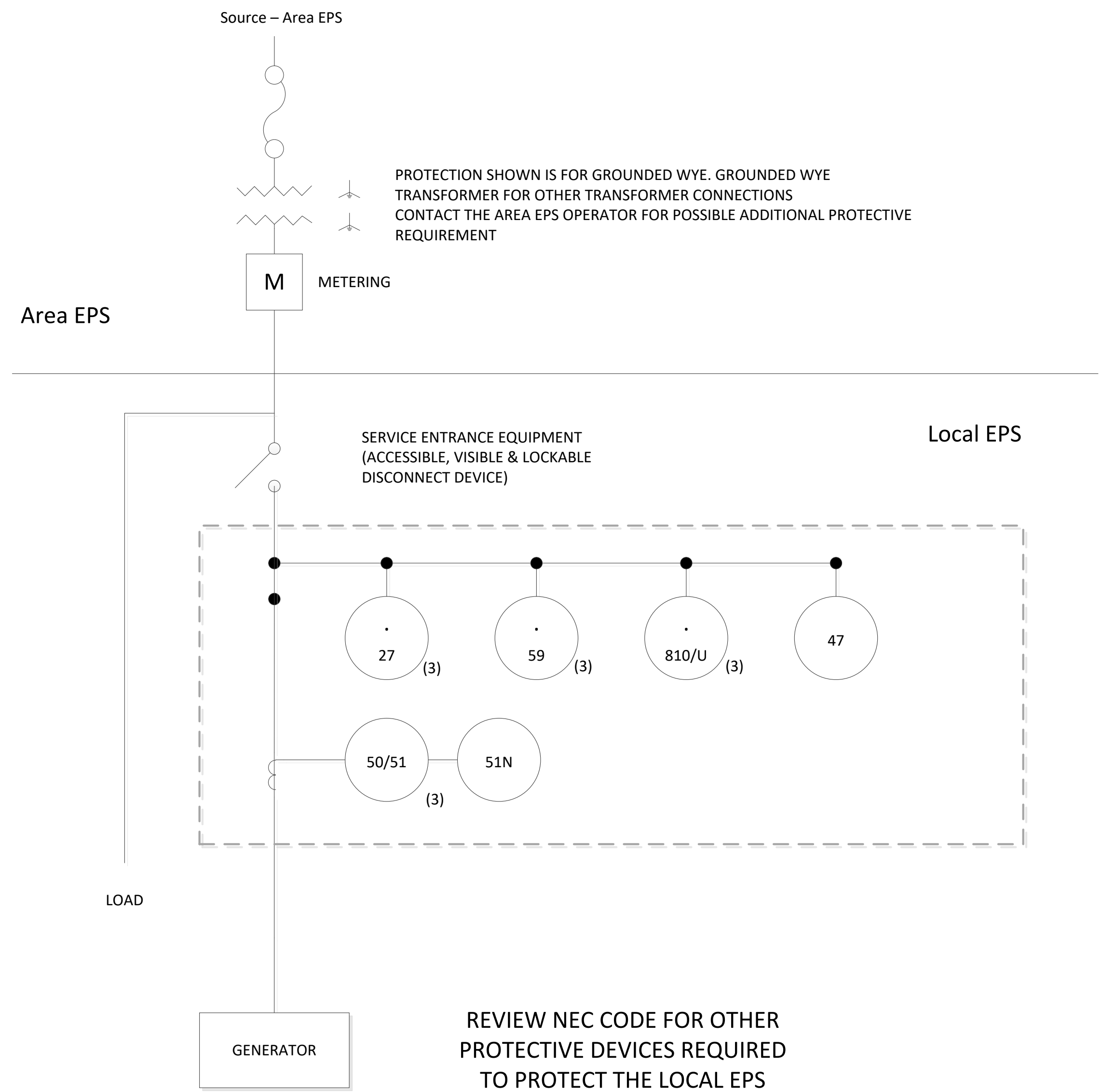
Device No.	Function	Trips
25	Synchronizer	
25SC	*Synch-check Relay	
27/59	*Under/Over Voltage	86/A
32	*Reverse Power (Trip	
	for power toward Area EPS)	86/B
47	Negative Sequence	86/A
50/51	*Phase Overcurrent	86/A
51N	*Ground Overcurrent	86/A
62PL	*Parallel Limit Timer	86/A
67	Directional Overcurrent	86/A
81	*Over/Under Frequency	86/A
86A	*Lockout Relay	A
86B	*Lockout Relay	B
TT	*Transfer Trip	86/A

TT is not required for Generation Systems smaller then 250kW

(1)(2)(3) Indicates Number of Phases to be Monitored

*Indicates Minimum Required Protection
Other Relays Shown are Recommended for Generator Protection

SOFT LOADING TRANSFER EXTENDED PARALLEL OPERATION	
DATE: April 2020	**Figure 4**



Device No.	Function
27/59	*Under/Over Voltage
47	Negative Sequence
50/51	Phase Overcurrent
51N	Ground Overcurrent
810/U	*Over/Under Frequency

(1)(2)(3) Indicates Number of Phases to be Monitored

*Indicates Minimum Required Protection
Other Relays Shown are Recommended for Generator Protection

INVERTER CONNECTED	
DATE: April 2020	Figure 5

Appendix B- Energy Storage System Configuration Diagrams

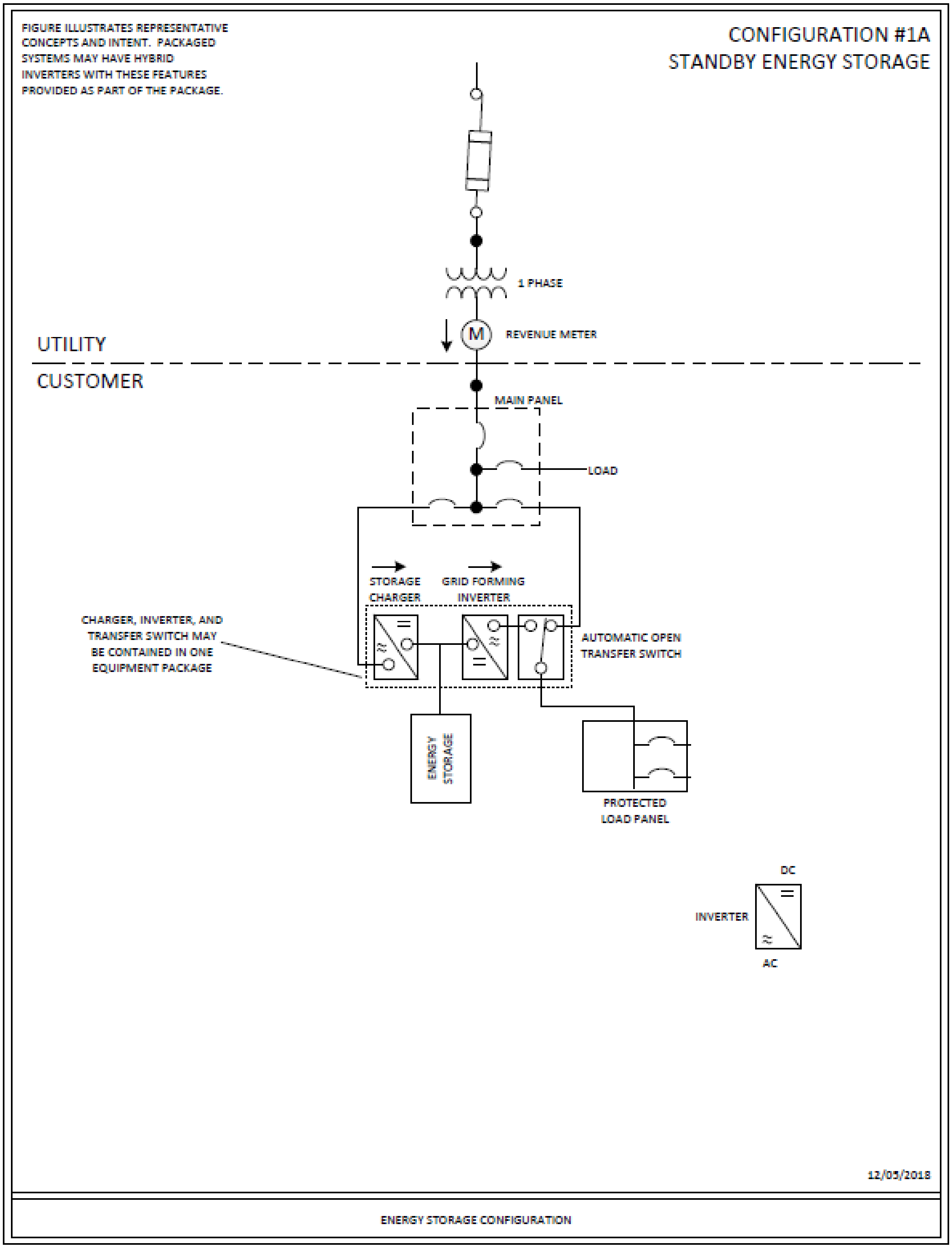
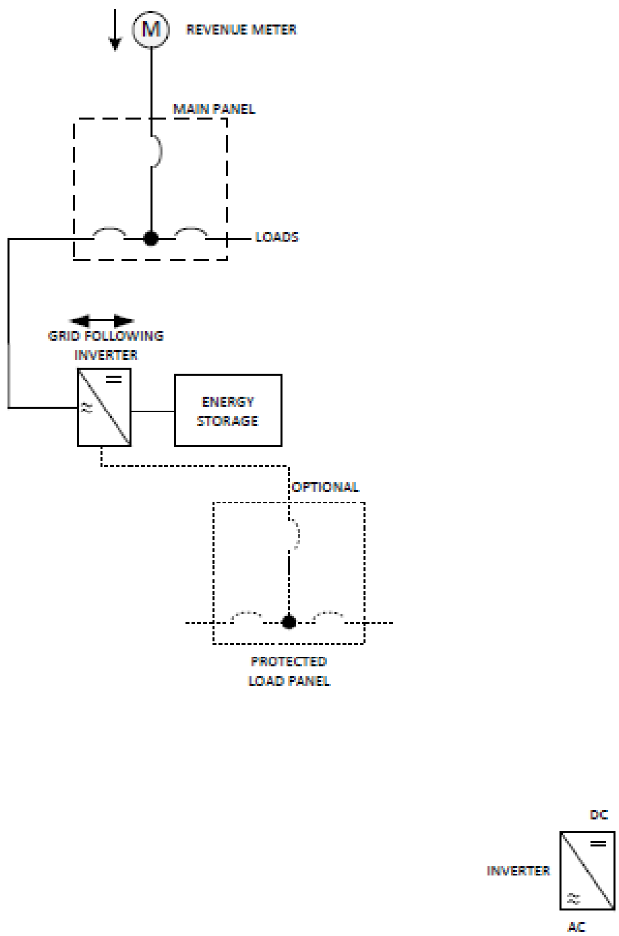


FIGURE ILLUSTRATES REPRESENTATIVE CONCEPTS AND INTENT. PACKAGED SYSTEMS MAY HAVE HYBRID INVERTERS WITH THESE FEATURES PROVIDED AS PART OF THE PACKAGE.
CONFIGURATION #1A
STANDBY ENERGY STORAGE
1 PHASE
M
REVENUE METER
UTILITY
CUSTOMER
MAIN PANEL
LOAD
STORAGE CHARGER
GRID FORMING INVERTER
CHARGER, INVERTER, AND TRANSFER SWITCH MAY BE CONTAINED IN ONE EQUIPMENT PACKAGE
AUTOMATIC OPEN TRANSFER SWITCH
ENERGY STORAGE
PROTECTED LOAD PANEL
DC
INVERTER
AC
12/05/2018
ENERGY STORAGE CONFIGURATION

FIGURE ILLUSTRATES REPRESENTATIVE CONCEPTS AND INTENT. PACKAGED SYSTEMS MAY HAVE HYBRID INVERTERS WITH THESE FEATURES PROVIDED AS PART OF THE PACKAGE.

CONFIGURATION #1B
PARALLEL ENERGY STORAGE
-STORAGE NOT ALLOWED TO EXPORT TO GRID



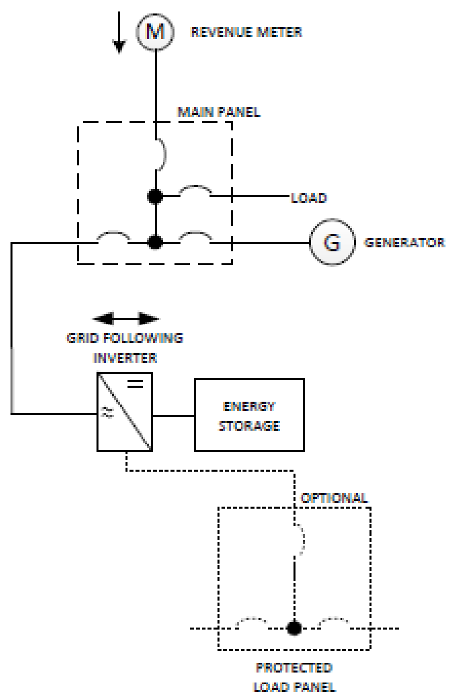
12/05/2018

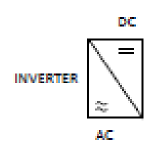
ENERGY STORAGE CONFIGURATION

FIGURE ILLUSTRATES REPRESENTATIVE CONCEPTS AND INTENT. PACKAGED SYSTEMS MAY HAVE HYBRID INVERTERS WITH THESE FEATURES PROVIDED AS PART OF THE PACKAGE.

CONFIGURATION #1C
PARALLEL ENERGY STORAGE + GENERATION

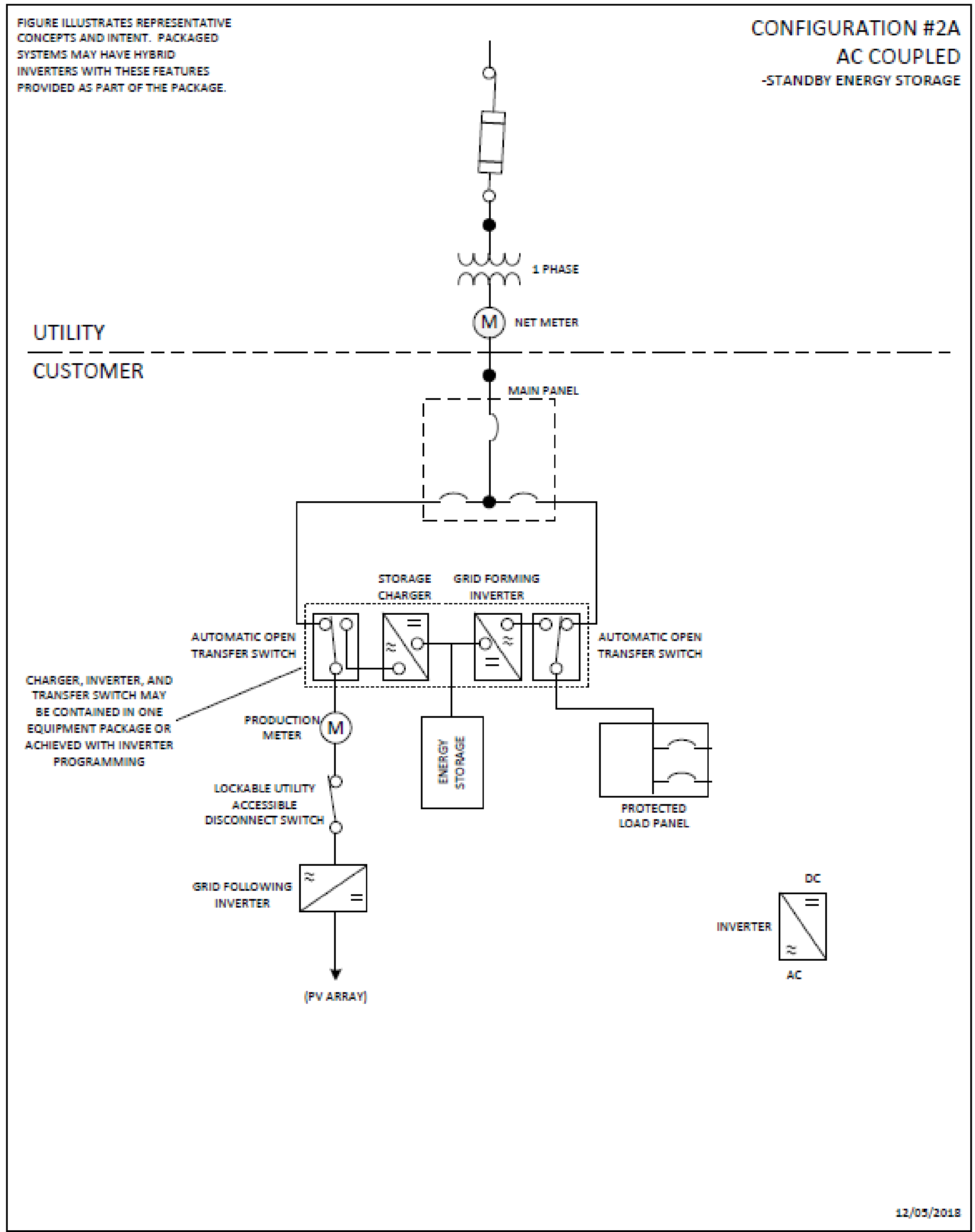
-GENERATION AND ENERGY STORAGE NOT ALLOWED TO EXPORT TO GRID





12/05/2018

DER + ENERGY STORAGE
CONFIGURATION



PV + ENERGY STORAGE CONFIGURATION

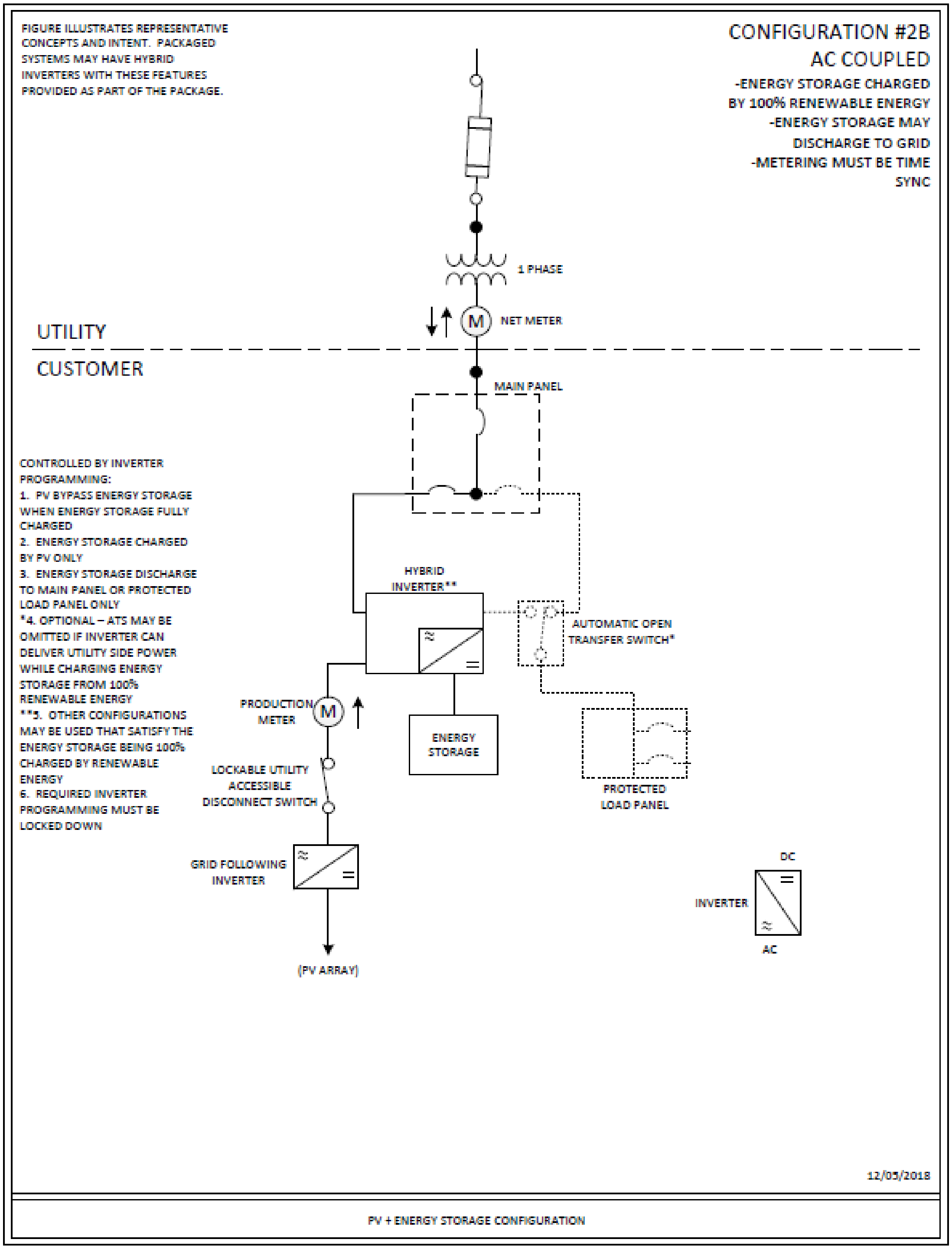


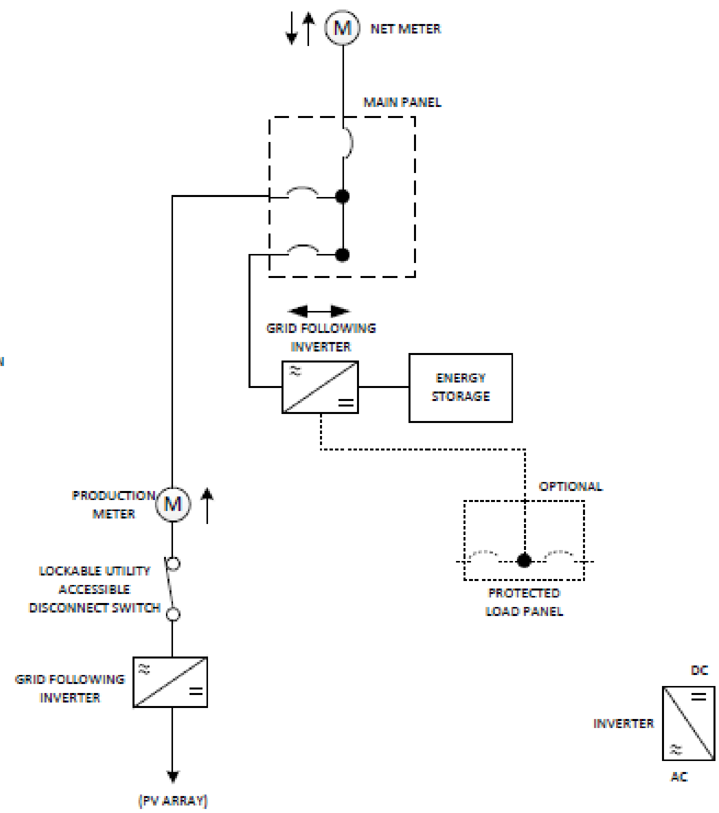
FIGURE ILLUSTRATES REPRESENTATIVE CONCEPTS AND INTENT. PACKAGED SYSTEMS MAY HAVE HYBRID INVERTERS WITH THESE FEATURES PROVIDED AS PART OF THE PACKAGE.
CONFIGURATION #2B
AC COUPLED
-ENERGY STORAGE CHARGED BY 100% RENEWABLE ENERGY
-ENERGY STORAGE MAY DISCHARGE TO GRID
-METERING MUST BE TIME SYNC
1 PHASE
M
NET METER
UTILITY
CUSTOMER
MAIN PANEL
CONTROLLED BY INVERTER PROGRAMMING:
1. PV BYPASS ENERGY STORAGE WHEN ENERGY STORAGE FULLY CHARGED
2. ENERGY STORAGE CHARGED BY PV ONLY
3. ENERGY STORAGE DISCHARGE TO MAIN PANEL OR PROTECTED LOAD PANEL ONLY
*4. OPTIONAL – ATS MAY BE OMITTED IF INVERTER CAN DELIVER UTILITY SIDE POWER WHILE CHARGING ENERGY STORAGE FROM 100% RENEWABLE ENERGY
**5. OTHER CONFIGURATIONS MAY BE USED THAT SATISFY THE ENERGY STORAGE BEING 100% CHARGED BY RENEWABLE ENERGY
6. REQUIRED INVERTER PROGRAMMING MUST BE LOCKED DOWN
HYBRID INVERTER**
AUTOMATIC OPEN TRANSFER SWITCH*
PRODUCTION METER
M
ENERGY STORAGE
PROTECTED LOAD PANEL
LOCKABLE UTILITY ACCESSIBLE DISCONNECT SWITCH
GRID FOLLOWING INVERTER
(PV ARRAY)
DC
INVERTER
AC
12/05/2018
PV + ENERGY STORAGE CONFIGURATION

FIGURE ILLUSTRATES REPRESENTATIVE CONCEPTS AND INTENT. PACKAGED SYSTEMS MAY HAVE HYBRID INVERTERS WITH THESE FEATURES PROVIDED AS PART OF THE PACKAGE.

CONFIGURATION #2C
AC COUPLED

-ENERGY STORAGE CHARGED FROM GRID OR RENEWABLE ENERGY
-ENERGY STORAGE NOT ALLOWED TO EXPORT TO GRID
-METERING MUST BE TIME SYNC

REGARDING THE ENERGY STORAGE INVERTER:
1. REQUIRED INVERTER PROGRAMMING MUST BE LOCKED DOWN
2. INVERTER MAY BE CONNECTED TO PROTECTED LOAD PANEL IF INVERTER CAN PROVIDE TRANSFER SWITCH FUNCTION



12/05/2018

PV + ENERGY STORAGE CONFIGURATION

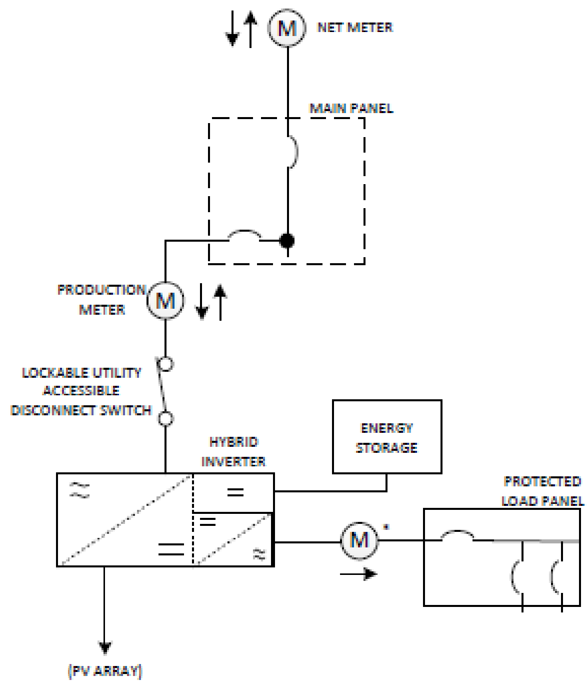
FIGURE ILLUSTRATES REPRESENTATIVE CONCEPTS AND INTENT. PACKAGED SYSTEMS MAY HAVE HYBRID INVERTERS WITH THESE FEATURES PROVIDED AS PART OF THE PACKAGE.

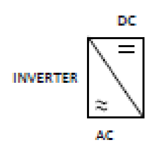
CONFIGURATION #3A
HYBRID EXAMPLE
METER OPTION

-ENERGY STORAGE MAY EXPORT
-METERING MUST BE TIME SYNC

1. GRID FOLLOW
2. GRID FORM
3. CHARGER
4. TRANSFER
5. REQUIRED INVERTER PROGRAMMING MUST BE LOCKED DOWN

*6. METER REQUIRED WHEN PROTECTED LOAD PANEL IS INSTALLED ON INVERTER SIDE OF PRODUCTION METER





12/05/2018

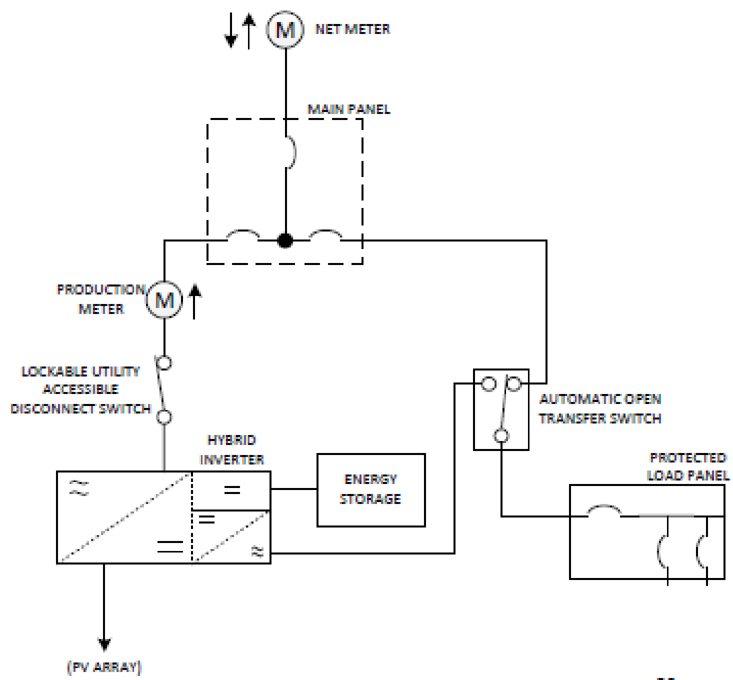
PV + ENERGY STORAGE CONFIGURATION

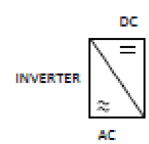
FIGURE ILLUSTRATES REPRESENTATIVE CONCEPTS AND INTENT. PACKAGED SYSTEMS MAY HAVE HYBRID INVERTERS WITH THESE FEATURES PROVIDED AS PART OF THE PACKAGE.

CONFIGURATION #3B
HYBRID EXAMPLE
TRANSFER OPTION

-ENERGY STORAGE MAY EXPORT
-METERING MUST BE TIME SYNC

1. GRID FOLLOW
2. GRID FORM
3. CHARGER
4. TRANSFER
5. REQUIRED INVERTER PROGRAMMING MUST BE LOCKED DOWN





12/05/2018

PV + ENERGY STORAGE CONFIGURATION

Appendix C- Energy Storage System Declarations

Declaration of Electric Storage Operation Limited to and in Compliance with NEC Article 702 and Configurations 1A and 2A in Section 10 of Xcel Energy's Technical Specifications Manual

Purpose of Declaration

Historically, Distributed Energy Resources (DERs) were assembled from discrete components or functional assemblies where the logic and operational approaches could be seen and analyzed. Today, much of the functionality is handled by an on-board computer following firmware and software instructions in order to achieve the desired results. Industry standards such as IEEE 1547 create a set of requirements that can be certified by Nationally Recognized Testing Laboratories for use on the Area EPS. However, many of the functionalities in Energy Storage Systems that are impactful to the Area EPS have no governing standard that they can be certified to, although efforts in the industry are underway. Lacking industry standards at this time for Energy Storage Systems, the functionalities need to be verified through extensive detailed review of the operating manuals and often inquiries with the manufacturer.

Declarations are used to provide supplemental information to MN DIP Exhibit B to ensure correct documentation and ratings are used for the "first use of a design" review, if needed, and to confirm subsequent applications for an approved package match the previously approved package in order to expedite approval. *An update to the firmware which modifies or adds operation modes and changes the required functionality is considered a facility modification and may be subject to a partial or full interconnection review*. This applies to all sources, whether generators or energy storage.

In Section 10.11.1.1 of the Area EPS Operator's Technical Specification Manual (TSM), Configuration 1A, the energy storage equipment is not capable of operating in parallel[31] with the Area EPS. The declaration allows interconnection of the energy storage device without an interconnection review if this mode is secure from change. In TSM Section 10.11.2.1, Configuration 2A, the energy storage equipment is not capable of operating in parallel with the Area EPS. If the energy storage system is operated ONLY in a non-paralleling mode, and such operating mode is secured from changes by unqualified personnel and end users[32], submittal of this signed declaration allows interconnection of the energy storage portion without an interconnection review by Xcel Energy. The NEM-eligible energy source portion of the facility, if added under the same application, must be reviewed and is subject to an Interconnection Agreement under MN DIP.

[31] See Definition section.
[32] Inaccessible may include locks or other physical security. Inaccessible and/or password protection must be restricted to the manufacturer/developer/installer.

Definitions

"Parallel Operation of Energy Storage" – a source operated in parallel with the Area EPS when it is connected to the Area EPS and can supply energy to the Interconnection Customer simultaneously with the Area EPS's supply of energy[33].

"**Operating Mode**" – a combination of the functionality in the physical configuration and the functionality in the software programming, some of which is not shown in the configuration diagram. Operating Mode is the combined function designed to achieve an Operating Objective that may vary with a change of settings. Operating Modes are established as a function, not by a diagram designation. Operating Modes include, but are not limited to, battery non-export, maximize self-consumption, maximize export, perform time shifting, and perform peak shaving. *A change of Operating Mode may constitute a change of Operating Objective*.

"**Operating Objective**" – the functional purpose of the DER operation achieved by the combination of the approved configuration and Operating Mode. *Any alterations to an Operating Mode may result in unacceptable changes to the Operating Objective as originally approved*. Such changes may render the facility ineligible for use without additional mitigations.

[33] A 1A or 2A energy storage system may charge from the Area EPS as long as it cannot discharge or contribute fault current to the Area EPS.

Declaration[34]

I, (print name and title of Installer/Developer)____ ____________declare that the electric storage system identified below complies with National Electric Code (NEC) Article 702 for optional standby power and complies with the applicable provisions of Xcel Energy's Technical Specification Manual, Section 10, for systems that are not capable of Parallel Operation of Energy Storage. (Applicable sections of the Technical Specifications Manual are Sections 10.11.1.1 and Sections 10.11.2.1.)

I further declare and/or agree that:

1. Applicable state or local safety inspections have been obtained, including specific inspection as to compliance to National Electric Code (NEC) Article 702 for optional standby power.

Installer/developer initials __________

2. System software and programming that is required to meet NEC Article 702[35] and the Technical Specification Manual provisions are inaccessible and/or password protected, with access restricted to manufacturer/developer/installer. This may include locks or other physical security or other means of securing the settings; or as mutually agreed upon on a case-by-case basis and identified in this declaration[36].

Installer/developer initials __________

3. Xcel Energy has the right to conduct an inspection to verify compliance at a later date if problems arise or indications of possible non-compliance to NEC Article 702 or the applicable Technical Specification Manual provisions are present.

Installer/developer initials __________

Applications that cannot parallel and cannot be readily changed to parallel operation may interconnect without review or Interconnection Agreement as stated in the Technical Specification Manual.

[34] Declaration must be agreed to and this form signed for eligibility for the non-parallel storage portion waiver of Interconnection Agreement as described in the Technical Specification Manual.
[35] If specific settings are required to achieve the 702 mode, these must be listed in Section 3 below.
[36] If the Operating Mode cannot be secured to ensure continued operation in a NEC 702 Standby compliant manner, the electric storage system is not eligible for use of the declaration in lieu of full interconnection review. A full interconnection review will examine all operating modes that are readily selectable and establish operating restrictions and mitigations to cover all selectable modes.

Electric Storage System (ESS) Details

This declaration covers the following electric storage system in whole or part as identified below:

Interconnection Customer Information:

Name ____

Address ____

City ______________________________ State ______ ZIP ______

Application ID
(Case #): ____

ESS Equipment Details

ESS Battery (B) Rating & ESS Inverter (I) Information

(B) Energy Capacity (kWh)	
(B) Real Power, max continuous charge (kW)	
(B) Real Power, recovery charge rate after Area EPS outage (kW)	
(B) Real Power, max continuous discharge (kW)	
(I) Real Power, peak output (kW)	
(I) Peak Output Duration Capability (sec)	
(I) Apparent Power, max continuous for charging (kVA)	
(I) Apparent Power, peak during discharge (kVA)	
(I) Power Factor Output Range (+/- range)	+/-
(I) Power Factor Capability at full rated real power (+/- range)	+/-
(I) Charging: using rectifier or inverter	
(B) Charge Rate kW (Maximum continuous)	
(B) Charge Rate kW (Recovery charge rate)	
(I) Firmware version	
(I) Operating Modes available	
(I) Operating Modes enabled	

Additional ESS Hardware: Description, Model and Part Number and General Specifications

To be used for devices such as the charge controller, external automatic transfer switches, etc.

Model Number(s)	
Model Name(s)	
UL Listing(s)	
Firmware Version	

Summary of Energy Storage Programming and Operation

(Include mode selection and specific settings required)

When ESS is transitioning the loads between off-grid and on-grid, the following steps will occur:

Prior to Area EPS outage, describe system operation	
Detail steps taken to disconnect from the Area EPS to meet NEC 702	
Detail steps taken to reconnect to the Area EPS to meet NEC 702	
Operating Modes available	
Operating Modes enabled	

System Installer:

I, (print name and title of Installer/Developer)______________________________certify that I have personal knowledge of the facts stated in this declaration and have the authority to make this declaration on behalf of the Interconnection Customer. I further certify that all of the statements and representations made in this declaration are true and correct.

Installer/Developer Signature: ____

Date: ______________________

Interconnection Customer:

I, (print name of Interconnection Customer)__________________________________ authorize the above identified Installer/Developer to represent the declarations on my behalf and will operate and maintain the system within the requirements set forth in this declaration for the life of the system in this authorized configuration.

Customer Signature: ____

Date: ______________________

Declaration of Electric Storage Operation Limited to and in Compliance with NEC Article 702 and Configurations 1B and 1C in Section 10 of Xcel Energy's Technical Specifications Manual

Purpose of Declaration

Historically, Distributed Energy Resources (DERs) were assembled from discrete components or functional assemblies where the logic and operational approaches could be seen and analyzed. Today, much of the functionality is handled by an on-board computer following firmware and software instructions in order to achieve the desired results. Industry standards such as IEEE 1547 create a set of requirements that can be certified by Nationally Recognized Testing Laboratories for use on the Area EPS. However, many of the functionalities in Energy Storage Systems that are impactful to the Area EPS have no governing standard that they can be certified to, although efforts in the industry are underway. Lacking industry standards at this time for Energy Storage Systems, the functionalities need to be verified through extensive detailed review of the operating manuals and often inquiries with the manufacturer.

Declarations are used to provide supplemental information to MN DIP Exhibit B to ensure correct documentation and ratings are used for the “first use of a design” review, if needed, and to confirm subsequent applications for an approved package match the previously approved package in order to expedite approval. *An update to the firmware which modifies or adds operation modes and changes the required functionality is considered a facility modification and may be subject to a partial or full interconnection review*. This applies to all sources, whether generators or energy storage.

Definitions

"Parallel Operation of Energy Storage" – a source operated in parallel with the Area EPS when it is connected to the Area EPS and can supply energy to the Interconnection Customer simultaneously with the Company's supply of energy[37].

"**Operating Mode**" – a combination of the functionality in the physical configuration and the functionality in the software programming, some of which is not shown in the configuration diagram. Operating Mode is the combined function designed to achieve an Operating Objective that may vary with a change of settings. Operating Modes are established as a function, not by a diagram designation. Operating Modes include, but are not limited to, battery non-export, maximize self-consumption, maximize export, perform time shifting, and perform peak shaving. *A change of Operating Mode may constitute a change of Operating Objective*.

"**Operating Objective**" – the functional purpose of the DER operation achieved by the combination of the approved configuration and Operating Mode. *Any alterations to an Operating Mode may result in unacceptable changes to the Operating Objective as originally approved*. Such changes may render the facility ineligible for use without additional mitigations.

[37] A 1A or 2A energy storage system may charge from the Area EPS as long as it cannot discharge or contribute fault current to the Area EPS.

Configurations Covered

Energy Storage System Configurations 2B and 2C, as detailed in Sections 10.11.1.2 and 10.11.1.3 in the TSM:

- 1B Non-Exporting Parallel Energy Storage System without Generation
- 1C Non-Exporting Parallel Energy Storage System and Non-Exporting Non-Renewable Generation

Key requirements and Functionality

1. Energy storage operates in parallel[38] with the Area EPS.
2. Generation, if present is non-renewable.
3. Metering is standard (non-net-metered).
4. Energy storage and generation, if present, are not allowed to export energy to the Area EPS[39].

The method of achieving #4 must be fully illustrated in the one-line diagram or described below. Any aspect that is imbedded in equipment and governed by firmware must be described, any additional equipment must be specified, and **specific settings needed to achieve #4 must be listed**.

System software and programming that is required to meet the Technical Specifications Manual provisions are inaccessible and/or password protected, with access restricted to manufacturer/developer/installer. This may include locks or other physical security or other means of securing the settings; or as mutually agreed upon on a case-by-case basis and identified in this declaration[40].

Xcel Energy has the right to conduct an inspection to verify compliance at a later date if problems arise or indications of possible non-compliance with the applicable Technical Manual Specifications provisions are present.

[38] See Definition section.
[39] Subject to the Inadvertent Export requirements as stated in the Section 8.4 of the Technical Specifications Manual.
[40] If the Operating Mode cannot be secured to ensure continued operation in a 1B or 1C compliant manner, as applicable, the facility will require full interconnection review that includes all operating modes that are readily selectable and establish operating restrictions and mitigations to cover all selectable modes.

Electric Storage System (ESS) Details

This declaration covers the following electric storage system in whole or part as identified below:

Interconnection Customer Information:

Name: ____

Address: ____

City: ______________________ State ______ ZIP ______

Application ID (Case #): ____

ESS Equipment Details

ESS Battery (B) Rating & ESS Inverter (I) Information

(B) Energy Capacity (kWh)	
(B) Real Power, max continuous charge (kW)	
(B) Real Power, recovery charge rate after Area EPS outage (kW)	
(B) Real Power, max continuous discharge (kW)	
(I) Real Power, peak output (kW)	
(I) Peak Output Duration Capability (sec)	
(I) Apparent Power, max continuous for charging (kVA)	
(I) Apparent Power, peak during discharge (kVA)	
(I) Power Factor Output Range (+/- range)	+/-
(I) Power Factor Capability at full rated real power (+/- range)	+/-
(I) Charging: using rectifier or inverter	
(B) Charge Rate kW (Maximum continuous)	
(B) Charge Rate kW (Recovery charge rate)	
(I) Firmware version	
(I) Operating Modes available	
(I) Operating Modes enabled	

Additional ESS Hardware: Description, Model and Part Number and General Specifications

To be used for devices such as the charge controller, external automatic transfer switches, etc.

Model Number(s)	
Model Name(s)	
UL Listing(s)	
Firmware Version	

Summary of Energy Storage Programming and Operation

(Include mode selection and specific settings required)

When ESS is transitioning the loads between off-grid and on-grid, the following steps will occur:

Prior to Area EPS outage, describe system operation	
Detail steps taken to disconnect from the Area EPS to meet NEC 702	
Detail steps taken to reconnect to the Area EPS to meet NEC 702	
Operating Modes available	
Operating Modes enabled	

System Installer:

I, (print name and title of Installer/Developer)______________________________certify that I have personal knowledge of the facts stated in this declaration and have the authority to make this declaration on behalf of the Interconnection Customer. I further certify that all of the statements and representations made in this declaration are true and correct.

Installer/Developer Signature: ____

Date: ______________________

Interconnection Customer:

I, (print name of Interconnection Customer)_______________________________ authorize the above identified Installer/Developer to represent the declarations on my behalf and will operate and maintain the system within the requirements set forth in this declaration for the life of the system in this authorized configuration.

Customer Signature:____

Date:_______________________

Declaration of Electric Storage Operation Limited to and in Compliance with NEC Article 702 and Configurations 2B and 2C in Section 10 of Xcel Energy's Technical Specifications Manual

Purpose of Declaration

Historically, Distributed Energy Resources (DERs) were assembled from discrete components or functional assemblies where the logic and operational approaches could be seen and analyzed. Today, much of the functionality is handled by an on-board computer following firmware and software instructions in order to achieve the desired results. Industry standards such as IEEE 1547 create a set of requirements that can be certified by Nationally Recognized Testing Laboratories for use on the Area EPS. However, many of the functionalities in Energy Storage Systems that are impactful to the Area EPS have no governing standard that they can be certified to, although efforts in the industry are underway. Lacking industry standards at this time for Energy Storage Systems, the functionalities need to be verified through extensive detailed review of the operating manuals and often inquiries with the manufacturer.

Declarations are used to provide supplemental information to MN DIP Exhibit B to ensure correct documentation and ratings are used for the "first use of a design" review, if needed, and to confirm subsequent applications for an approved package match the previously approved package in order to expedite approval. *An update to the firmware which modifies or adds operation modes and changes the required functionality is considered a facility modification and may be subject to a partial or full interconnection review*. This applies to all sources, whether generators or energy storage.

Definitions

“Parallel Operation of Energy Storage” – a source operated in parallel with the Area EPS when it is connected to the Area EPS and can supply energy to the Interconnection Customer simultaneously with the Company’s supply of energy[41].

“**Operating Mode**” – a combination of the functionality in the physical configuration and the functionality in the software programming, some of which is not shown in the configuration diagram. Operating Mode is the combined function designed to achieve an Operating Objective that may vary with a change of settings. Operating Modes are established as a function, not by a diagram designation. Operating Modes include, but are not limited to, battery non-export, maximize self-consumption, maximize export, perform time shifting, and perform peak shaving. *A change of Operating Mode may constitute a change of Operating Objective*.

“**Operating Objective**” – the functional purpose of the DER operation achieved by the combination of the approved configuration and Operating Mode. *Any alterations to an Operating Mode may result in unacceptable changes to the Operating Objective as originally approved*. Such changes may render the facility ineligible for use without additional mitigations.

[41] A 1A or 2A energy storage system may charge from the Area EPS as long as it cannot discharge or contribute fault current to the Area EPS.

Configurations Covered

Energy Storage System Configurations 2B and 2C, as detailed in Sections 10.11.2.2 and 10.11.2.3 in the TSM:

- 2B Parallel Energy Storage with Renewable Generation, Net-Metering, with Export
- 2C Parallel Non-Exporting Energy Storage with Renewable Generation, Net Metering

Key requirements and Functionality

1. Energy storage operates in parallel[42] with the Area EPS.
2. Generation is renewable.
3. Revenue metering is net metering.
4. Production metering, if required, is installed.
5. 2B may export to Area EPS if the storage is **100% charged**[43] from on-site renewable generation[44].
6. 2C storage may not export to the Area EPS but may be charged by mixed sources.

The methods of achieving #5 and #6, as applicable, must be fully illustrated in the one-line diagram or described below. Any aspect that is embedded in equipment and governed by firmware must be described, any additional equipment must be specified, and **specific settings needed to assure compliance must be listed**.

System software and programming that is required to meet the Technical Specifications Manual provisions are inaccessible and/or password protected, with access restricted to manufacturer/developer/installer. This may include locks or other physical security or other means of securing the settings; or as mutually agreed upon on a case-by-case basis and identified in this declaration[45].

Xcel Energy has the right to conduct an inspection to verify compliance at a later date if problems arise or indications of possible non-compliance with the applicable Technical Specifications Manual provisions are present.

[42] See Definition section.
[43] If a battery exports when non-compliant, the site including PV is not eligible for net metering.
[44] Charging must be 100% renewable energy. Any storage mixture of non-renewable energy disqualifies 2B from exporting. If the battery charging is not 100% renewable, the configuration may be used with non-export from the battery to the grid.
[45] If the Operating Mode cannot be secured to ensure continued operation in a 2B or 2C compliant manner, as applicable, the facility will require full interconnection review that includes all operating modes that are readily selectable and establish operating restrictions and mitigations to cover all selectable modes.

Electric Storage System (ESS) Details

This declaration covers the following electric storage system in whole or part as identified below:

Interconnection Customer Information:

Name: ______________________________

Address: ______________________________

City: ______________________ State ______ ZIP ______

Application ID (Case #): ______________________________

ESS Equipment Details

ESS Battery (B) Rating & ESS Inverter (I) Information

(B) Energy Capacity (kWh)	
(B) Real Power, max continuous charge (kW)	
(B) Real Power, recovery charge rate after Area EPS outage (kW)	
(B) Real Power, max continuous discharge (kW)	
(I) Real Power, peak output (kW)	
(I) Peak Output Duration Capability (sec)	
(I) Apparent Power, max continuous for charging (kVA)	
(I) Apparent Power, peak during discharge (kVA)	
(I) Power Factor Output Range (+/- range)	+/-
(I) Power Factor Capability at full rated real power (+/- range)	+/-
(I) Charging: using rectifier or inverter	
(B) Charge Rate kW (Maximum continuous)	
(B) Charge Rate kW (Recovery charge rate)	
(I) Firmware version	
(I) Operating Modes available	
(I) Operating Modes enabled	

Additional ESS Hardware: Description, Model and Part Number and General Specifications

To be used for devices such as the charge controller, external automatic transfer switches, etc.

Model Number(s)	
Model Name(s)	
UL Listing(s)	
Firmware Version	

Summary of Energy Storage Programming and Operation
(Include mode selection and specific settings required)

When ESS is transitioning the loads between off-grid and on-grid, the following steps will occur:

Prior to Area EPS outage, describe system operation	
Detail steps taken to disconnect from the Area EPS to meet NEC 702	
Detail steps taken to reconnect to the Area EPS to meet NEC 702	
Operating Modes available	
Operating Modes enabled	

System Installer:

I, (print name and title of Installer/Developer)______________________________certify that I have personal knowledge of the facts stated in this declaration and have the authority to make this declaration on behalf of the Interconnection Customer. I further certify that all of the statements and representations made in this declaration are true and correct.

Installer/Developer Signature: ____

Date: ______________________

Interconnection Customer:

I, (print name of Interconnection Customer) ___________________________________ authorize the above identified Installer/Developer to represent the declarations on my behalf and will operate and maintain the system within the requirements set forth in this declaration for the life of the system in this authorized configuration.

Customer Signature: ____

Date: ___________

Declaration of Electric Storage Operation Limited to and in Compliance with NEC Article 702 and Configurations 3A and 3B in Section 10 of Xcel Energy's Technical Specifications Manual

Purpose of Declaration

Historically, Distributed Energy Resources (DERs) were assembled from discrete components or functional assemblies where the logic and operational approaches could be seen and analyzed. Today, much of the functionality is handled by an on-board computer following firmware and software instructions in order to achieve the desired results. Industry standards such as IEEE 1547 create a set of requirements that can be certified by Nationally Recognized Testing Laboratories for use on the Area EPS. However, many of the functionalities in Energy Storage Systems that are impactful to the Area EPS have no governing standard that they can be certified to, although efforts in the industry are underway. Lacking industry standards at this time for Energy Storage Systems, the functionalities need to be verified through extensive detailed review of the operating manuals and often inquiries with the manufacturer.

Declarations are used to provide supplemental information to MN DIP Exhibit B to ensure correct documentation and ratings are used for the "first use of a design" review, if needed, and to confirm subsequent applications for an approved package match the previously approved package in order to expedite approval. *An update to the firmware which modifies or adds operation modes and changes the required functionality is considered a facility modification and may be subject to a partial or full interconnection review*. This applies to all sources, whether generators or energy storage.

Definitions

"Parallel Operation of Energy Storage" – a source operated in parallel with the Area EPS when it is connected to the Area EPS and can supply energy to the Interconnection Customer simultaneously with the Company's supply of energy[46].

"**Operating Mode**" – a combination of the functionality in the physical configuration and the functionality in the software programming, some of which is not shown in the configuration diagram. Operating Mode is the combined function designed to achieve an Operating Objective that may vary with a change of settings. Operating Modes are established as a function, not by a diagram designation. Operating Modes include, but are not limited to, battery non-export, maximize self-consumption, maximize export, perform time shifting, and perform peak shaving. *A change of Operating Mode may constitute a change of Operating Objective*.

"**Operating Objective**" – the functional purpose of the DER operation achieved by the combination of the approved configuration and Operating Mode. *Any alterations to an Operating Mode may result in unacceptable changes to the Operating Objective as originally approved*. Such changes may render the facility ineligible for use without additional mitigations.

[46] A 1A or 2A energy storage system may charge from the utility as long as it cannot discharge or contribute fault current to the utility.

Configurations Covered

Energy Storage System Configurations 3A and 3B, as detailed in Sections 10.11.3.1 and 10.11.3.2 in the TSM:

- 3A Parallel DC Coupled Energy Storage with Renewable Generation, Net-Metering, with Export
- 3B Parallel DC Coupled Energy Storage with Renewable Generation, Net-Metering, ATS, with Export

Key requirements and Functionality

1. Energy storage operates in parallel[47] with the Area EPS via hybrid inverter.
2. Generation is renewable.
3. Revenue metering is net metering.
4. Production metering, if required, is installed.
5. 3A and 3B may export to Area EPS if the storage is **100% charged**[48] from on-site renewable generation[49].
6. If a Protected Load Panel (PLP) is present on the inverter side of any required production meter for configuration 3A, a second load meter must be installed on the PLP.

The method of achieving #5 must be fully illustrated in the one-line diagram or described below. Any aspect that is embedded in equipment and governed by firmware must be described, any additional equipment must be specified, **and specific settings needed to assure compliance must be listed**.

System software and programming that is required to meet the Technical Specifications Manual provisions are inaccessible and/or password protected, with access restricted to manufacturer/developer/installer. This may include locks or other physical security or other means of securing the settings; or as mutually agreed upon on a case-by-case basis and identified in this declaration[50].

Xcel Energy has the right to conduct an inspection to verify compliance at a later date if problems arise or indications of possible non-compliance with the applicable TSM provisions are present.

[47] See Definition section.
[48] If battery exports when non-compliant, the site including PV is not eligible for net metering
[49] Charging must be 100% renewable energy. Any storage mixture of non-renewable energy disqualifies 3A or 3B from exporting. If the battery charging is not 100% renewable, the configuration may be used with non-export from the battery to the grid.
[50] If the Operating Mode cannot be secured to ensure continued operation in a 3A or 3B compliant manner, as applicable, the facility will require full interconnection review that includes all operating modes that are readily selectable and establish operating restrictions and mitigations to cover all selectable modes.

Electric Storage System (ESS) Details

This declaration covers the following electric storage system in whole or part as identified below:

Interconnection Customer Information:

Name: ______________________________

Address: ______________________________

City: ______________________ State ______ ZIP ______

Application ID (Case #): ______________________________

ESS Equipment Details

ESS Battery (B) Rating & ESS Inverter (I) Information

(B) Energy Capacity (kWh)	
(B) Real Power, max continuous charge (kW)	
(B) Real Power, recovery charge rate after Area EPS outage (kW)	
(B) Real Power, max continuous discharge (kW)	
(I) Real Power, peak output (kW)	
(I) Peak Output Duration Capability (sec)	
(I) Apparent Power, max continuous for charging (kVA)	
(I) Apparent Power, peak during discharge (kVA)	
(I) Power Factor Output Range (+/- range)	+/-
(I) Power Factor Capability at full rated real power (+/- range)	+/-
(I) Charging: using rectifier or inverter	
(B) Charge Rate kW (Maximum continuous)	
(B) Charge Rate kW (Recovery charge rate)	
(I) Firmware version	
(I) Operating Modes available	
(I) Operating Modes enabled	

Additional ESS Hardware: Description, Model and Part Number and General Specifications

To be used for devices such as the charge controller, external automatic transfer switches, etc.

Model Number(s)	
Model Name(s)	
UL Listing(s)	
Firmware Version	

Summary of Energy Storage Programming and Operation

(Include mode selection and specific settings required)

When ESS is transitioning the loads between off-grid and on-grid, the following steps will occur:

Prior to Area EPS outage, describe system operation	
Detail steps taken to disconnect from the Area EPS to meet NEC 702	
Detail steps taken to reconnect to the Area EPS to meet NEC 702	
Operating Modes available	
Operating Modes enabled	

System Installer:

I, (print name and title of Installer/Developer)______________________________certify that I have personal knowledge of the facts stated in this declaration and have the authority to make this declaration on behalf of the Interconnection Customer. I further certify that all of the statements and representations made in this declaration are true and correct.

Installer/Developer Signature____

Date______________________

Interconnection Customer:

I, (print name of Interconnection Customer) ___________________________________ authorize the above identified Installer/Developer to represent the declarations on my behalf and will operate and maintain the system within the requirements set forth in this declaration for the life of the system in this authorized configuration.

Customer Signature:____

Date: ______________________

STATE OF MINNESOTA TECHNICAL INTERCONNECTION AND INTEROPERABILTY REQUIREMENTS

TIIR

Abstract

The technical requirements for interconnection of Distributed Energy Resources to the distribution system to be used in conjunction with electric utilities' Technical Specification Manuals

Approved by Commission's Order dated January 22, 2020

Contents

1. Overview

1.1 General

Distributed Energy Resources (DER) connected to the electric distribution system span a wide range of sizes and electrical characteristics utilizing technology that is constantly evolving. The design of electrical distribution systems varies widely from that which is required to serve the rural customer to that which is needed to serve the large commercial customer.

The electric distribution system is designed to operate in both normal and contingency configurations. Normal system configurations or normal operation exists when all distribution facilities and equipment are available and fully functional and the Area EPS's switches are in their normal state. Contingency system configuration or contingency operation is the condition in which the failure of a single or multiple element(s) affect the normal operation of the Area EPS or when the Area EPS's switch positions are in the abnormal state. Contingency configurations can arise from electric component failures or from planned maintenance.

The scope of this document, referred to as the Technical Interconnection and Interoperability Requirements (TIIR), is to describe common statewide requirements for interconnection of DER systems with the Area EPS. The Area EPS's specific specifications or technology requirements are detailed with the Area EPS Operator's Technical Specification Manual (TSM). Both the TIIR and the TSM documents are based upon the IEEE 1547 standards and other applicable national standards. The intent of these documents is to provide consumers and installers with a clear set of technical requirements and guide the interconnection of DER systems with the local electrical distribution system using a safe, reliable, and cost-effective design.

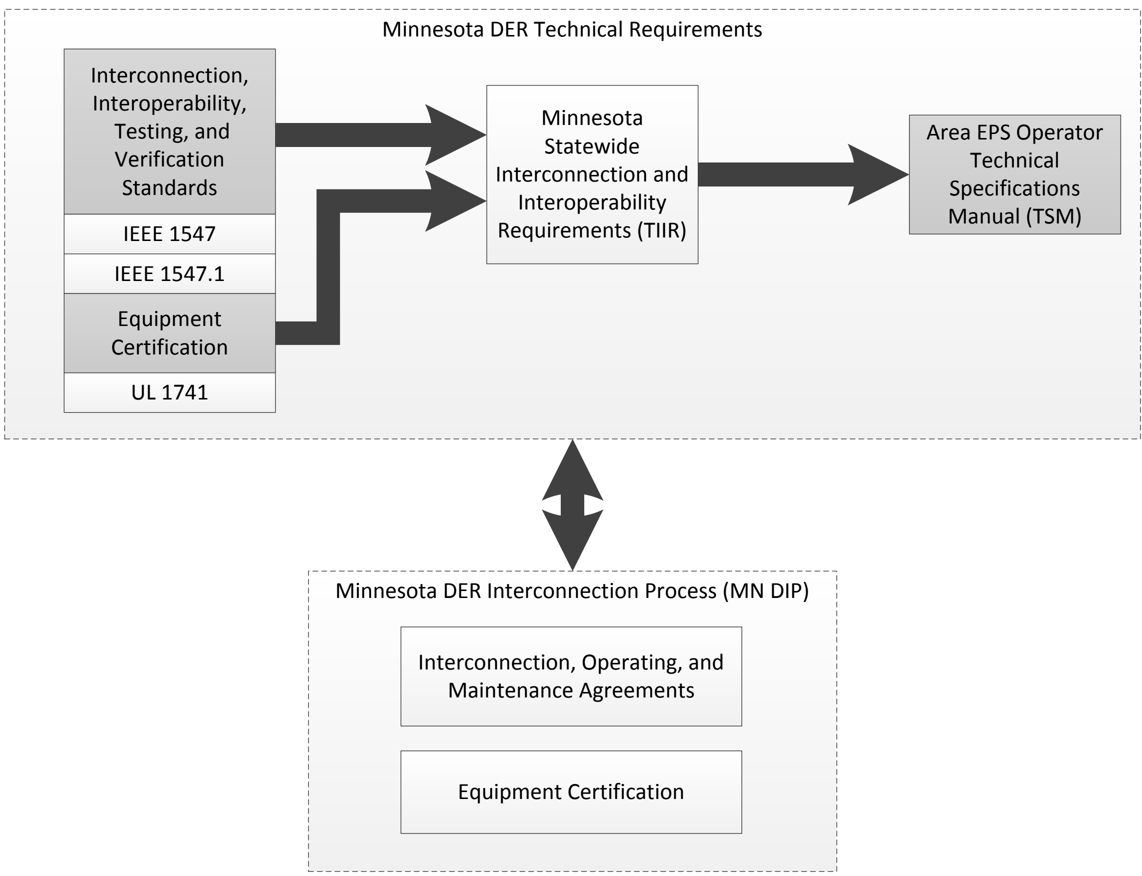
With so many variations in Area EPS designs, it becomes complex to create a single set of interconnection requirements that fits all DER interconnection situations. The Area EPS Operator must maintain a level of engineering judgment in order to interconnect the wide range of technologies over a variety of Area EPS and DER characteristics and designs[1]. The Area EPS Operator shall follow applicable industry standards and good utility practice when applying engineering judgment.

This document sets forth statewide technical requirements for DER interconnecting to an Area EPS in the state of Minnesota. The Minnesota statewide TIIR have been established to align with the Area EPS Operators' duty and obligation to plan and operate a distribution system that economically delivers electric power while focusing on safety, reliability, and quality of service.

[1] Another factor driving the need for engineering judgment is the increasingly varied mixture of legacy DER equipment from different era standards. Currently national standards do not exist to address interconnection engineering considerations that may arise due the mix of current and legacy technology. For example, a portion of the Area EPS with legacy inverters and advanced inverters will respond differently to abnormal conditions when compared to apportion of the Area EPS that contains only advanced inverters. Legacy inverters are grandfathered in under the standards under which they were installed.

The statewide TIIR shall be used in conjunction with individual Area EPS Operator interconnection Technical Specification Manuals (TSM). Where industry standards exist, the TSM shall align with the applicable standards including IEEE 1547. The TSM also lists the Area EPS Operator specific requirements and provides further detail in areas where no common statewide or national industry standards exist[2]. In addition to allowing for differences in distribution electric and information systems design and operation, the Area EPS Operator's TSM allows for expedited adoption of new industry standards and best practices as they become available without creating conditions where the statewide interconnection standards and national standards become out-of-sync. Figure 1 depicts the interaction of key DER industry technical standards, statewide technical standards (TIIR), Area EPS Operator's technical specifications manuals (TSMs), and the Minnesota Distributed Energy Resources Interconnection Process (MN DIP).

Figure 1. Interaction of DER Standards



All requirements in the most recent versions of IEEE 1547 and 1547.1 are adopted by the TIIR. IEEE 1547, *IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces*, and IEEE 1547.1, *IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems*, provides the foundation of interconnection and

[2] For example, industry standards do not define conditions or size thresholds for when metering, interoperability, protection, or other requirements shall be applied. Also, interconnection standards only address the electrical and interoperability interface between the Local EPS and Area EPS.

interoperability technical requirements which applies to all DER interconnections. Other standards, recommended practices, and guide documents may be applicable to individual projects and should be referenced based on the DER technology and configuration being proposed and characteristics of the Area EPS[3] to which it is being interconnected. In general, the content of industry standards is not reproduced here, but instead the additional standards are referenced in Section 3 of this document.

Consistent with IEEE 1547, these requirements apply to the interconnection of all DER units within the Local EPS that parallel with the Area EPS. The requirements in the TIIR shall be applied at the Reference Point of Applicability (RPA)[4], unless otherwise specified by the TIIR or mutually agreed upon. The DER shall not create or contribute to an intentional Area EPS island, unless approved by the Area EPS Operator.

When the need arises, the Area EPS should coordinate with Transmission Providers and Regional Transmission Operators to accommodate requests from these entities which cross the transmission and distribution electric interface while still maintaining the Area EPS Operators' primary responsibility of providing safe, reliable, and quality service for Area EPS retail customers.

Protection systems requirements in the TIIR, are structured to protect the Area EPS, Area EPS customers, and the public. Details of protection systems requirements are specified in the Area EPS Operator's TSM. The protection of the DER and the Local EPS is solely the responsibility of the Interconnection Customer and is not addressed in these technical requirements.

The DER Operator shall be responsible for complying with all applicable local, independent, state and federal codes such as building codes, National Electric Code (NEC), National Electrical Safety Code (NESC) and local municipality noise and emissions standards. As required by Minnesota State law (326B.36 Subd. 5 Duty of Electrical Utility), the Area EPS may require proof of complying with the National Electrical Code before the interconnection is completed, through approval by an electrical inspector recognized by the Minnesota State Board of Electricity. The DER Operator shall maintain the DER facilities using industry standards and best practices in order to reduce the likelihood of an unintended DER operating state causing adverse impacts to customers or the Area EPS.

In the event of an inconsistency between various laws, rules, standards, contracts, or policies over interconnection requirements, the resolution to this inconsistency shall be resolved by assigning an order of precedence from highest to lowest as follows:

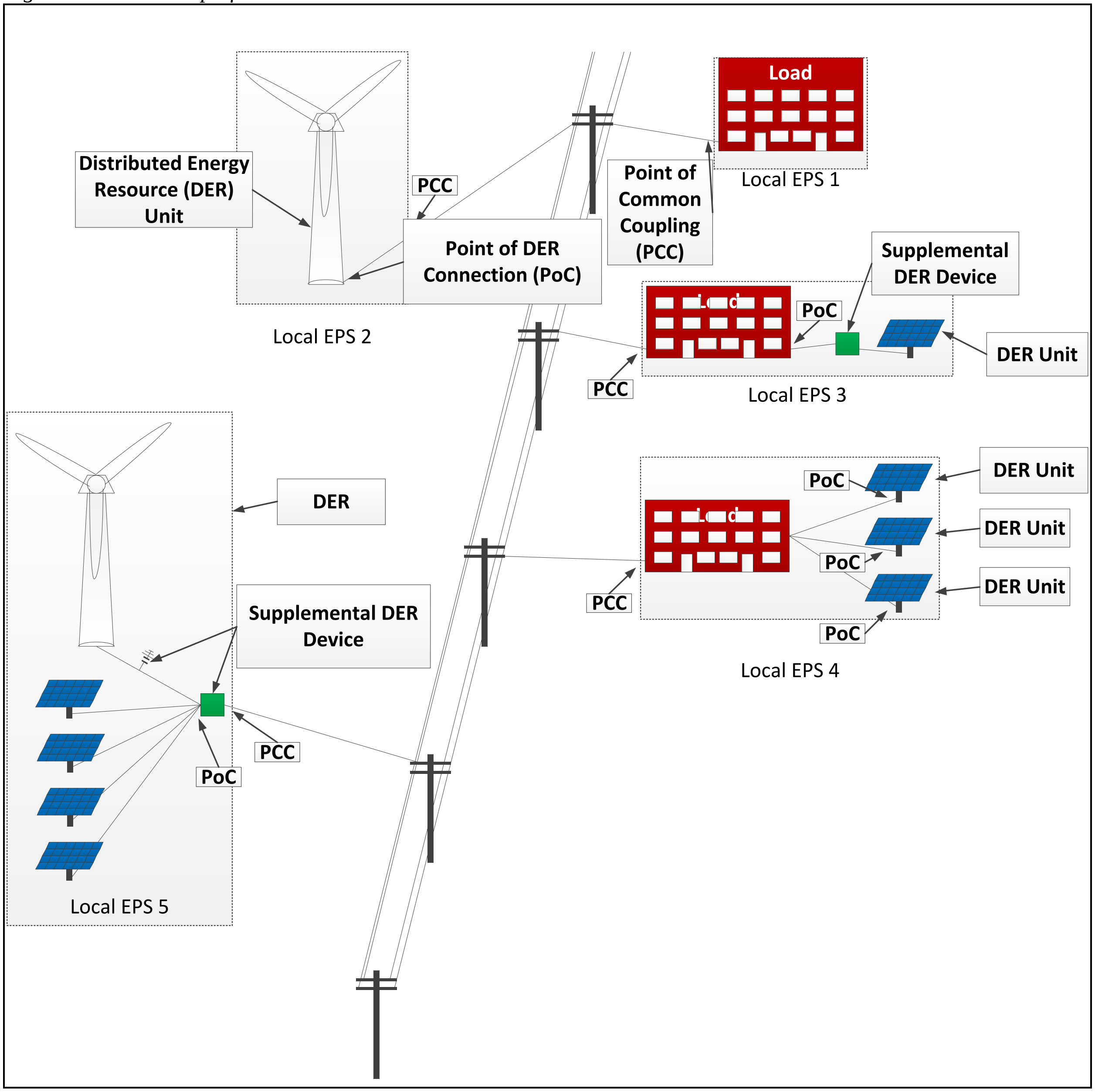
1. State of Minnesota statutes
2. Minnesota Public Utilities Commission approved standards, tariffs or orders
3. National Standards, Codes, and Certifications

[3] For example, low voltage secondary networks have unique interconnection concerns and the recommended practice in IEEE 1547.6 should be used in conjunction with IEEE 1547 and IEEE 1547.1.
[4] See IEEE 1547 and the TIIR Annex B for further information on the RPA. The RPA is the point at which IEEE 1547 interconnection and interoperability requirements are required to be met.

4. Agreements between the Area EPS Operator and the DER Operator
5. Area EPS Operator published documents

Figure 2 contains a depiction and description of the relationship of some key terms used throughout this document. The usage of these terms as it relates to Figure 2 is consistent with IEEE 1547 definitions. Each of the terms are defined in Section 3-B of this document. Additional discussion of the terms is found in Annex B.

Figure 2. Relationship of Terms



1.2 Scope

The statewide TIIR applies to all DER technology sized at 10 MW and less in AC nameplate capacity[5] that is interconnected at secondary or primary distribution voltages and is operated in parallel[6] with an Area EPS. The TIIR applies to DER for any duration of parallel operation. Non-exporting DER that operate in parallel with the Area EPS are subject to these technical standards.

1.3 Purpose

This TIIR document provides the technical requirements common to all regulated electric utilities in Minnesota for the interconnection and interoperability of DER with associated Area EPS. It provides references and requirements relevant to safety, security, performance, operation, interoperability, testing and verification in harmony with other industry, national and state standards.

1.4 Coordination with Area EPS Operator's Specific Technical Standards

Where this TIIR document does not provide technical guidance, the Interconnection Customer needs to review the Area EPS Operator's specific TSM document, the Area EPS Operator's web site or contact the generation interconnection coordinator at the Area EPS Operator. The following is a brief listing of some of the areas which further technical guidance is to be provided within the Area EPS Operator's TSM.[7]

1) Project Coordination Information
2) Protection system requirements for the DER interconnection
3) Operational standards and requirements
4) DER monitoring and communication requirements
5) Metering requirements in support of specific rates and operational needs

The Area EPS Operator's TSM documents are to be designed to provide utility specific details aligned with the TIIR requirements. The Area EPS Operators' TSM document shall be limited to detailing requirements which are in support of the requirements contained within the TIIR and MN DIP. Additional requirements not contemplated by the TIIR may be mutually agreed upon between the Parties**.**

At the time this document is being written, IEEE 1547.1 is undergoing a revision which is expected to significantly affect requirements surrounding DER testing and verification. The publication of the updated IEEE 1547.1 standard may necessitate updating this document soon thereafter, most notably addressing changes to Section 12.

[5] The 10 MW AC nameplate capacity limitation is based on Minn. Stat.§ 216B.1611.
[6] National Electric Code and Area EPS specific requirements apply for standby generators and emergency back-up generators with, a break-before-make type of interconnection.
[7] See Annex C for an anticipated list of additional topics in a TSM.

1.5 Convention for Word Usage

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

1.6 Transition Period

All requirements of the TIIR are immediately applicable unless requiring equipment that conforms with IEEE 1547-2018 advanced functionalities.

Area EPS Operators cannot require the use of certified equipment that meets the requirements of IEEE 1547-2018 until such time the equipment is readily available. At such time certified equipment first becomes available, the Area EPS Operator and DER Owner may mutually agree to utilize the certified equipment and functionalities in conformance with the requirements of IEEE 1547-2018. At such time when certified equipment is readily available[8], the entire TIIR shall be applicable.

[8] Refer to UL 1741 for timeline of readily available certified equipment that meets the requirements of IEEE 1547-2018.

2. References

The standards, codes, certification, guides and recommended practices listed in this section are active as of the publication of this document. These standards, codes, certifications, guides and recommended practices may be superseded, withdrawn, or additional applicable revisions may become available after the publication of this document. Later revisions of the technical references listed below may be available and supersede the versions referenced in this document. At the time an interconnection application is submitted, the Area EPS Operator and the DER Operator shall use the most recent applicable technical reference. Application of industry standards, codes, certifications, guides and recommended practices shall be consistent with the standard governing body's manuals, policies, and procedures.

IEC TR 61000-3-7:2008, Electromagnetic compatibility (EMC) - Part 3-7: Limits - Assessment of emission limits for the connection of fluctuating installations to MV, HV and EHV power systems.

IEC 61000-4-3:2006+A1:2007+A2:2010, Electromagnetic compatibility (EMC) - Part 4-3: Testing and measurement techniques - Radiated, radio-frequency, electromagnetic field immunity test.

IEC 61000-4-5:2014+A1:2017, Electromagnetic compatibility (EMC) - Part 4-5: Testing and measurement techniques – Surge immunity test.

IEEE Std 1547-2018, IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces

IEEE Std 1547.1, IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems

IEEE Std 1547.2, Application Guide for IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems

IEEE Std 1547.3-2007, Guide for Monitoring Information Exchange and Control of DR Interconnected with Electric Power Systems

IEEE Std 1547.4-2011, IEEE Guide for Design, Operation, and Integration of Distributed Resource Island System with Electric Power Systems

IEEE Std 1547.6-2011, IEEE Recommended Practice for Interconnecting Distributed Resources with Electric Power Systems Distribution Secondary Networks

IEEE Std 1547.7-2013, IEEE Guide for Conducting Distribution Impact Studies for Distributed Resource Interconnection

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

IEEE Std 1453-2015, IEEE Recommended Practice for the Analysis of Fluctuating Installation on Power Systems

IEEE Std 1453.1-2012 (Adoption of IEC/TR 61000-3-7:2008) - IEEE Guide--Adoption of IEC/TR 61000-3-7:2008, Electromagnetic compatibility (EMC)--Limits--Assessment of emission limits for the connection of fluctuating installations to MV, HV and EHV power systems

IEEE Std C37.90-2005, IEEE Standard for Relay Systems Associated with Electric Power Apparatus

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

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

IEEE C37.95-2014, IEEE Guide for Protective Relaying of Utility-Consumer Interconnections

IEEE Std C50.12-2005, IEEE Standard for Salient-Pole 50 Hz and 60 Hz Synchronous Generators and Generator/Motors for Hydraulic Turbine Applications Rated 5 MVA and Above.

IEEE Std C50.13-2014, IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above.

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

IEEE Std C62.42-2016, Guide for the Application of Component Surge-Protective Devices for Use in Low-Voltage [Equal to or Less than 1000 V (ac) Or 1200 V (dc)] Circuits

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

IEEE Std C62.92.2-2017, IEEE Guide for the Application of Neutral Grounding in Electric Utility Systems, Part II – Grounding of Synchronous Generator Systems

IEEE Std C62.92.6-2017, IEEE Guide for the Application of Neutral Grounding in Electric Utility Systems, Pat VI

IEEE Std 32-1972 (Reaff 1990), IEEE Standard Requirements, Terminology, and Test Procedure for Neutral Grounding Devices

IEEE Std 141-1993, IEEE Recommended Practice for Electric Power Distribution for Industrial Plants – Red Book

IEEE Std 142-2007, IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems – Green Book

IEEE Std 242-2001, Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems

IEEE Std 446-1995, Recommended Practice for Emergency and Standby Power Systems for Industrial and Commercial Applications

IEEE Std 2030-2011, Guide for Smart Grid Interoperability of Energy Technology and Information Technology Operation with the Electric Power System (EPS), End-Use Applications, and Loads

IEEE Std 2030.5-2013, IEEE Adoption of Smart Energy Profile 2.0 Application Protocol Standard.

IEEE Std 1815-2012, IEEE Standard for Electric Power Systems Communications-Distributed Network Protocol (DNP3)

ANSI C84.1-2016, Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)

UL 1741, Inverters, Converters, and Controllers for use in Independent Power Systems

ANSI C2-2007, National Electrical Safety Code", Published by the Institute of Electrical and Electronics Engineers, Inc.

NFPA 70, National Electrical Code", Published by the National Fire Protection Association

IEC 61850-7-420:2009, Communication networks and systems for power utility automation - Part 7-420: Basic communication structure - Distributed energy resources logical nodes

IEC 62351-12:2016, Power systems management and associated information exchange - Data and communications security - Part 12: Resilience and security recommendations for power systems with distributed energy resources (DER) cyber-physical systems

3. Definitions and Acronyms

3.1 General

The definitions of terms used in this document are consistent with the IEEE 1547, IEEE 1547.1, and Minnesota DER Interconnection Process definitions, to the extent possible.

The origins of definitions are noted below in Table 1. The associated symbols are shown as a superscript to each term in order to denote the document from which the definition originates. For the purpose of denoting origin, the definition notes are to be considered part of the definition unless otherwise denoted with a separate symbol.

Table 1. Origin of Defined Terms

Document of origin for definition	Symbol
IEEE 1547-2018	x
Minnesota Interconnection Process and Agreement (MN DIP/MN DIA) - 2018	ʌ
Minnesota Statewide Interconnection Technical Standards (TIIR)	Г
Other (additional footnote is shown to denote origin)	ɵ

3.2 Definitions

Abnormal Operating Performance Category[x]: The grouping for a set of requirements that specify technical capabilities and settings for a DER under abnormal operating conditions, i.e., outside the *continuous operation* region.

Area Electric Power System (Area EPS) [^]: The electric power distribution system connected at the Point of Common Coupling

Area Electric Power System Operator (Area EPS Operator) [^]: An entity that owns, controls, or operates the electric power distribution systems that are used for the provision of electric service in Minnesota.

Area EPS Operator Technical Specification Manual (TSM)[r]: The Area EPS Operator's technical manual containing interconnection and interoperability requirements specific to the Area EPS. The TSM is considered part of the Minnesota technical requirements framework.

Affected Systems[^]: Another Area EPS Operator's System, Transmission Owner's Transmission System, or Transmission System connected generation which may be affected by the proposed interconnection.

Authority Governing Interconnection Requirements (AGIR)[x]: A cognizant and responsible entity that defines, codifies, communicates, administers, and enforces the policies and procedures for allowing electrical interconnection of DER to the Area EPS. This may be a regulatory agency, public utility commission, municipality, cooperative board of directors, etc. The degree of AGIR involvement will vary in scope of application and level of enforcement across jurisdictional boundaries. This authority may be delegated by the cognizant and responsible entity to the Area EPS operator or *bulk power system* operator.

NOTE—Decisions made by an authority governing interconnection requirements should consider various stakeholder interests, including but not limited to Load Customers, *Area EPS operators*, *DER operators*, and *bulk power system* operator.

Bulk Power System (BPS) [x]: Any electric generation resources, transmission lines, interconnections with neighboring systems, and associated equipment.

NOTE [ɵ] [9] – The usage of BPS in this document is intended to be generally aligned with the NERC definition of bulk electric systems, which includes transmission facilities with rated voltages above 100 kV; generating units with individual nameplate ratings above 25 MVA with a common point of connection a voltage at 100 kV or above; and generating plants with total capacity ratings above 75 MVA with a common point of connection at 100 kV and above. The term Transmission Power System is used to describe the remaining transmission facilities that are rated for voltages less than 100 kV.

Cease to Energize[x]: Cessation of active power delivery under steady state and transient conditions and limitation of reactive power exchange.

[9] The note associated with BPS is intended to be largely aligned with the NERC definition. This is intended to supplement the definition of IEEE 1547 to reduce confusion since the NERC definition is a subset of the IEEE 1547 definition. A new definition, Transmission Power System is introduced in the section to cover the remaining facilities (i.e. < 100 kV transmission lines).

NOTE 1—This may lead to momentary cessation or trip.

NOTE 2—This does not necessarily imply, nor exclude, disconnection, isolation, or a trip.

NOTE 3—Limited reactive power exchange may continue as specified, e.g., through filter banks.

NOTE 4—Energy storage systems are allowed to continue charging but are allowed to cease from actively charging when the maximum state of charge (maximum stored energy) has been achieved.

Certified Equipment[^]: UL 1741 listing is a common form of DER inverter certification. See **Error! Reference source not found.** and Attachment 5: Certification of Distributed Energy Resource Equipment of the MN DIP.

Continuous Operation[x]: Exchange of current between the DER and an EPS within prescribed behavior while connected to the Area EPS and while the applicable voltage and the system frequency is within specified parameters.

Continuous Operation Region[x]: The performance operating region corresponding to *continuous operation.*

Customers[r]: Individuals or entities that own a Local EPS that is connected to the Area EPS with the purpose of purchasing electric power service from the Area EPS Operator

Distributed Energy Resource (DER) [x]: a source of electric power that is not directly connected to a bulk power system. DER includes both generators and energy storage technologies capable of exporting active power to an EPS. An interconnection system or a supplemental DER device that is necessary for compliance with this standard is part of a DER.

NOTE 1—Controllable loads used for demand response are not included in the definition of DER.

NOTE 2[r]—See MN DIP Glossary of Terms or Figure 2 in IEEE 1547-2018.

Distributed Energy Resource Operator (DER Operator) [x]: The entity responsible for operating and maintaining the distributed energy resource.

Distribution Energy Resource Unit (DER Unit) [x]: An individual DER device inside a group of DER that collectively forms a system.

Electric Power System (EPS) [x]: Facilities that deliver electric power to a load.

NOTE [r] —This may include generation units. See MN DIP Glossary of Terms or Figure 2 in IEEE 1547-2018.

Energize[x]: Active power outflow of the DER to an EPS under any conditions (e.g., steady state and transient).

Energy Storage System (ESS)[r] : An electric system that stores active power for later injection into the Local EPS or Area EPS.

ESS Control Mode[Γ]**:** The function that manages the real and reactive power flow from or to an ESS in response to certain parameters, (such as time, price signals, frequency or external signals, etc.)

Enter Service[X]**:** Begin operation of the DER with an energized Area EPS.

Intentional Island[X]**:** A planned electrical island that is capable of being energized by one or more Local EPSs. These (1) have DER(s) and load, (2) have the ability to disconnect from and to parallel with the Area EPS, (3) include one or more Local EPS(s), and (4) are intentionally planned.

NOTE—An intentional island may be an *intentional Area EPS island* or an *intentional Local EPS island* (also: "facility island").

Interconnection[X]**:** The result of the process of adding DER to an Area EPS, whether directly or via intermediate Local EPS facilities.

Interconnection Agreement[^]: The terms and conditions between the Area EPS Operator and Interconnection Customer (Parties). See MN DIP Section 1.1.5 for when the Uniform Statewide Contract or MN DIA applies.

Interconnection Customer[^]**:** The person or entity, including the Area EPS Operator, whom will be the owner of the DER that proposes to interconnect a DER(s) with the Area EPS Operator's Distribution System. The Interconnection Customer is responsible for ensuring the DER(s) is designed, operated and maintained in compliance with the Minnesota Technical Requirements.

Interconnection Facilities [^] – The Area EPS Operator's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the DER and the Point of Common Coupling, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the DER to the Area EPS Operator's System. Some examples of Customer Interconnection Facilities include: supplemental DER devices, inverters, and associated wiring and cables up to the Point of DER Connection. Some examples of Area EPS Operator Interconnection Facilities include sole use facilities; such as, line extensions, controls, relays, switches, breakers, transformers and shall not include Distribution Upgrades or Network Upgrades.

Interconnection System[X]**:** The collection of all interconnection and interoperability equipment and functions, taken as a group, used to interconnect a DER to an Area EPS.

Interface[X]**:** An electrical or logical connection from one entity to another that supports one or more energy or data flows implemented with one or more power or data links.

Interoperability[X]**:** The capability of two or more networks, systems, devices, applications, or components to externally exchange and readily use information securely and effectively. (IEEE Std 2030)

Inverter[X]**:** A machine, device, or system that changes direct-current power to alternating-current power.

NOTE[r] - While the classical definition of inverter originating from IEEE 1547 considers power flow in a single direction, the usage of the term in this document indicates potential for bi-directional capabilities. The machine, device, or system can change power from direct-current to alternating-current and the machines, devices, or systems may also have capabilities to change power from alternating-current to direct-current.

Island[x]: A condition in which a portion of an Area EPS is energized solely by one or more Local EPS through the associated PCCs while that portion of the Area EPS is electrically separated from the rest of the Area EPS on all phases to which the DER is connected. When an island exists, the DER energizing the island may be said to be "islanding".

Load[x]: Devices and processes in a local EPS that use electrical energy for utilization, exclusive of devices or processes that store energy but can return some or all of the energy to the local EPS or Area EPS in the future.

Local DER Communication Interface[x]: A local interface capable of communicating to support the information exchange requirements specified in this standard for all applicable functions that are supported in the DER.

Local Electric Power System (Local EPS) [x]: An EPS contained entirely within a single premises or group of premises.

Maintenance Requirements [ɵ]: The maintenance terms and conditions between the Area EPS Operator and Interconnection Customer (Parties) included in the Operating Agreement as Attachment 5 of the Interconnection Agreement.

Material Modifications [^]: A modification to machine data, equipment configuration or to the interconnection site of the DER at any time after receiving notification by the Area EPS Operator of a complete Interconnection Application that has a material impact on the cost, timing, or design of any Interconnection Facilities or Upgrades, or a material impact on the cost, timing or design of any Interconnection Application with a later Queue Position or the safety or reliability of the Area EPS.[10]

[10] A Material Modification shall include, but may not be limited to, a modification from the approved Interconnection Application that: (1) changes the physical location of the point of common coupling; such that it is likely to have an impact on technical review; (2) increases the nameplate rating or output characteristics of the Distributed Energy Resource; (3) changes or replaces generating equipment, such as generator(s), inverter(s), transformers, relaying, controls, etc., and substitutes equipment that is not like-kind substitution in certification, size, ratings, impedances, efficiencies or capabilities of the equipment; (4) changes transformer connection(s) or grounding; and/or (5) changes to a certified inverter with different specifications or different inverter control settings or configuration. A Material Modification shall not include a modification from the approved Interconnection Application that: (1) changes the ownership of a Distributed Energy Resource; (2) changes the address of the Distributed Energy Resource, so long as the physical point of common coupling remains the same; (3) changes or replaces generating equipment such as generator(s), inverter(s), solar panel(s), transformers, relaying, controls, etc. and substitutes equipment that is a like-kind substitution in certification, size, ratings, impedances, efficiencies or capabilities of the equipment; and/or (4) increases the DC/AC ratio but does not increase the maximum AC output capability of the Distributed Energy Resource in a way that is likely to have an impact on technical review.

Minnesota DER Interconnection Agreement (MN DIA)[^]: The Minnesota Distributed Energy Resource Interconnection Agreement. See MN DIP Section 1.1.5 for when the Uniform Statewide Contract or MN DIA applies.

Minnesota DER Interconnection Process (MN DIP)[^]: The Minnesota Distributed Energy Resource Interconnection Process which is statewide interconnection standards for regulated utilities.

MN Technical Requirements [^]: The term including all of the DER technical interconnection requirement documents for the state of Minnesota; including: 1) Attachment 2 Distributed Generation Interconnection Requirements established in the Commission's September 28, 2004 Order in E-999/CI-01-1023) until superseded and upon Commission approval of updated Minnesota DER Technical Interconnection and Interoperability Requirements in E-999/CI-16-521.

Momentary Cessation[x]: Temporarily *cease to energize* an EPS, while connected to the Area EPS, in response to a disturbance of the *applicable voltages* or the system frequency, with the capability of immediate Restore Output of operations when the applicable voltages and the system frequency returns to within defined ranges.

Nameplate Ratings[x]: nominal voltage (V), current (A), maximum active power (kW), apparent power (kVA), and reactive power (kvar) at which a DER is capable of sustained operation.

> NOTE—For Local EPS with multiple DER units, the aggregate DER nameplate rating is equal to the sum of all DERs nameplate rating in the Local EPS, not including aggregate capacity limiting mechanisms such as coincidence factors, plant controller limits, etc., that may be applicable for specific cases.

Normal Operating Performance Category[x]: The grouping for a set of requirements that specify technical capabilities and settings for DER under normal operating conditions, i.e., inside the *continuous operation* region.

Non-export, Non-exporting[Γ]: When the DER is sized and designed such that the DER output is used for host load only and is designed and operated to prevent the transfer of electrical energy from the DER to an Area EPS or TPS.

Operating Requirements[^]: Any operating and technical requirements that may be applicable due to the Transmission Provider's technical requirements or Minnesota Technical Requirements, including those set forth in the MN DIA.

Parallel Operation[Γ]: a source operated in parallel with the grid when it is connected to the distribution grid and can supply energy to the customer simultaneously with the Company supply of energy.

Permissive Operation: Operating mode where the DER performs ride-through either in *mandatory operation* or in *momentary cessation*, in response to a disturbance of the *applicable voltages* or the system frequency.

Permissive Operation Region: The performance operating region corresponding to permissive operation.

Point of Common Coupling (PCC)[x]: The point of connection between the Area EPS and the Local EPS.

NOTE 1—See MN DIP Glossary of Terms or Figure 2 in IEEE 1547.

NOTE 2—Equivalent, in most cases, to "service point" as specified in the National Electrical Code™ and the National Electrical Safety Code™.

Point of Distributed Energy Resources Connection (point of DER connection–PoC)[x]: The point where a DER unit is electrically connected in a Local EPS and meets the requirements of this standard exclusive of any load present in the respective part of the Local EPS.

NOTE 1—See MN DIP Glossary of Terms or Figure 2 in IEEE 1547.

NOTE 2—For (a) DER unit(s) that are not self-sufficient to meet the requirements without (a) supplemental DER device(s), the point of DER connection is the point where the requirements of this standard are met by DER (b) device(s) in conjunction with (c) supplemental DER device(s) exclusive of any load present in the respective part of the Local EPS.

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

Range of Allowable Settings[x]: The range within which settings may be adjusted to values other than the specified default settings.

Reference Point of Applicability (RPA)[x]: The location where the interconnection and interoperability performance requirements specified in this standard apply.

Regional Transmission Operator (RTO)[r]: The functional entity that maintains the real-time operating reliability of the bulk electric power within a reliability coordinator area.

NOTE – This definition is based on the IEEE 1547 regional reliability coordinator definition. In Minnesota, i.e. the Midcontinent Independent System Operator (MISO) and Southwest Power Pool (SPP), perform this function based on territory.

Restore Output[x]: Return operation of the DER to the state prior to the abnormal excursion of voltage or frequency that resulted in a ride-through operation of the DER.

Return to Service[x]: Enter service following recovery from a trip.

Ride-Through[x]: Ability to withstand voltage or frequency disturbances inside defined limits and to continue operating as specified.

Secondary Network[r]: An AC distribution system where the low-voltage of the distribution transformers are connected to a common network for supplying electricity directly to consumers. There are two types of secondary networks: grid networks and spot networks.

Supplemental DER Device[x]**:** Any equipment that is used to obtain compliance with some or all of the interconnection requirements of this standard.

NOTE—Examples include capacitor banks, STATCOMs, harmonic filters that are not part of a DER unit, protection devices, plant controllers, etc.

Technical Interconnection and Interoperability Requirements (TIIR)[r]**:** The supplemental set of DER interconnection and interoperability requirements in this document which together with each Area EPS Operator's Technical Specification Manual (TSM) and industry interconnection standards, make up the Minnesota Technical Requirements.

Technical Specification Manual (TSM) [r]**:** The Area EPS Operator specific interconnection and interoperability requirements for interconnection of Distributed Energy Resources which together with the Technical Interconnection and Interoperability Requirements (TIIR) and industry interconnection standards, make up the Minnesota Technical Requirements.

Transmission Power System[r] **(TPS):** Any transmission or generation facility that is not part of the bulk power system.

NOTE - In general, this is transmission facilities rated at voltages less than 100 kV; transmission generation units with power ratings less 25 MVA; and generation plants with total capacity ratings less than 75 MVA.

Trip[x]**:** Inhibition of immediate return to service, which may involve disconnection.

NOTE—Trip executes or is subsequent to cessation of energization.

Type Test[x]: a test of one or more devices manufactured to a certain design to demonstrate, or provide information that can be used to verify, that the design meets the requirements specified in this standard.

3.3 Acronyms

AGIR	Authority Governing Interconnection Requirements
BPS	Bulk Power System
DER	Distributed Energy Resource
EPS	Electric Power System
ESS	Energy Storage System
MN DIA	Minnesota Distributed Energy Resource Interconnection Agreement
MN DIP	Minnesota Distributed Energy Resource Interconnection Process
PoC	Point of Distributed Energy Resource Connection

PCC	Point of Common Coupling
RPA	Reference Point of Applicability
RTO	Regional Transmission Operator
TIIR	Technical Interconnection and Interoperability Requirements (this standard document)
TPS	Transmission Power System
TSM	Technical Specifications Manual (supplemental Area EPS Operator document)

4. Performance Categories

4.1 Introduction

The IEEE 1547 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. Performance categories describe minimum equipment capability and the required ranges of allowable settings. The next two subsections, Performance Category Assignment and Use of Default Parameters, contain the Minnesota specific application requirements based on the available performance categories defined in IEEE 1547 standard.

There are a number of 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 could be driven by Area EPS, TPS or BPS needs. Regional coordination and standardization in selection of abnormal performance categories is necessary. The entity determining the appropriate performance categories is specified by the IEEE 1547 standard. The subsections below contain the specific requirements that have been determined to be appropriate for application in Minnesota.

Category A and B specify reactive power capability and voltage regulation performance requirements. Category B is intended for use where DER penetration is 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 by the Area EPS Operator, Section 4.2.A.

Categories I, II, and III differentiate performance requirements for DER response to abnormal conditions. The Minnesota Public Utilities Commission is delegated authority by the IEEE 1547 standard to provide guidance for assigning abnormal performance categories which is specified in Section 4.2.B. 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.

I. Category I encompasses minimum BPS essential needs
II. 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[11].
III. 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.

4.2 Performance Category Assignment

Performance Category assignment is specific to the state of Minnesota. Based on IEEE 1547, the Area EPS Operator assigns normal performance categories - Category A and B, as shown in Section 4.2.A. The Minnesota Public Utilities Commission assigns abnormal Categories I, II, and III, as shown in Section 4.2.B. The process of assigning performance categories considers Area EPS needs; as well as TPS and BPS needs on a regional and wider basis.

A. Normal – Category A and B

Considering existing[12] and future high penetration DER conditions, and the example decision tree in Annex B of IEEE 1547, the assignment of the category for reactive power capabilities and voltage regulation performance of DER in Minnesota shall be as follows:

Table 2. Normal Performance Category Assignment

Technology	Normal performance category
Inverter-based DER	Category B
Synchronous machine generation	Category A

The above assignment of Categories A and B is expected to cover the vast majority of interconnections. Any instances that do not fall within the above assignment shall be:

1) reviewed on a case-by-case basis, with the Area EPS Operator making determination[13] for requiring Category A or B; or
2) performance category assignments specified in the Area EPS Operator's TSM

B. Abnormal – Categories I, II, and III

The abnormal performance category assignment should also consider a future level of DER penetration that could impact the TPS or BPS if not properly coordinated. The

[11] Fault Induced Delayed Voltage Recovery is the main load consideration. This situation arises where distribution loads that typically consume reactive power draw increased levels of reactive power due to a low voltage event. The additional reactive power consumption of the distribution loads leads to a slower rebound in voltage returning to nominal levels.
[12] At the time this document is being written, portions of the Area EPS in Minnesota are exhibiting power flow characteristics of a high penetration DER environment. Based on these localized pockets of high penetration at the Area EPS level, a future with high penetration at the Area EPS, TPS, and BPS is considered when assigning performance categories in Minnesota.
[13] The Area EPS Operator should consider Annex B of IEEE 1547 when making these determinations on a case-by-case basis or in TSM requirements.

Area EPS Operators in the state of Minnesota shall constructively work with the Regional Transmission Operator to provide a recommendation whether Category II or Category III is the proper default category assignment for inverter-based DER. The decision shall balance the needs of the Area EPS and Local EPS with TPS and BPS considerations. Until a decision is made by the Regional Transmission Operator within that region, all synchronous machine DER shall be assigned Category I and all inverter-based DER shall be assigned Category II. Any instances that do not fall within the above assignment shall:

1) be reviewed on a case-by-case basis, with the Area EPS Operator making determination[14] for requiring Category I, II or III; or
2) have performance category assignment specified in the Area EPS Operators TSM.

4.3 Use of Default Parameters

The DER shall use the IEEE 1547 default parameter settings for all capabilities and performance requirements of the applicable performance category unless otherwise specified by the TIIR or Area EPS Operator's TSM. In order to protect BPS and TPS reliability and to produce a response from DER that can be modeled, deviating from the statewide default parameters for abnormal performance category settings should be a rare occurrence.

4.4 Assignment of Alternative Abnormal Operating Performance Category

Normal Operating Performance Category assignments are shown in Section 4.2.A in this document. Abnormal Operating Performance Category assignments may be reviewed on a case-by-case basis, with the Area EPS Operator making determination for requiring Category A or B or listed in the Area EPS Operator's TSM.

Upon mutual agreement, provided no adverse effects are caused to the distribution system, TPS or BPS, exceptions may be made for Categories I, II and III if the DER technology is not able to meet the assignment outline in Section 4.2.B. This should be a rare occurrence. Should the DER technology readily exist to meet the stated assignments in Section 4.2.B, no exception shall be allowed.

5. Reactive Power Capability and Voltage/Power Control Performance

5.1 Introduction

A widely observed effect of relatively high levels of DER is reverse power flow causing an elevation of voltage near the DER source. The Area EPS Operator is responsible for maintaining voltage within standard ANSI C84.1 Range A for normal operations. Depending on the Area EPS characteristics for the system serving the location of interconnection, an economic solution to mitigate high-voltage caused by DER may be to implement DER active power and reactive power control functions. The implementation of these functions can

[14] The Area EPS Operator should consider Annex B of IEEE 1547 when making these determinations on a case-by-case basis or in TSM requirements.

contribute to an Area EPS Operator's ability to operate the system in a safe and reliable manner as increasing levels of DER are deployed. The use of these functions can allow higher levels of DER deployment in an economic manner. In general, reactive power control functions should be used to control voltage[15] for normal Area EPS conditions, by injecting or absorbing vars. The voltage-active power control function should be used for abnormal Area EPS conditions (for example temporary feeder configuration) which work by reducing active power output in order to reduce the severity or alleviate the high voltage condition.

5.2 General

As defined by IEEE 1547, DER reactive power capability, required by the applicable performance category[16], shall be available for use by the Area EPS Operator for the purpose of mitigating impacts of DER on the Area EPS. The real and reactive power capabilities shall be available for implementation to resolve DER grid impacts after the initial installation, even if functions are not initially implemented. The Area EPS Operator shall notify the DER Operator when a change in reactive power control modes is required to address Area EPS operating needs. Any implementation of functions shall adhere to applicable agreements.

The decision to use reactive power control functions can affect transmission power system reactive power flow patterns. TPS and BPS impacts should be considered by the Area EPS Operator when specifying reactive power control strategies in the Area EPS Operator's TSM.

The Area EPS Operator shall specify the control mode and settings for the DER. The DER Operator shall implement the settings in a reasonable timeframe. When a communication channel exists from the Area EPS Operator's communication interface to the Local DER Communication Interface, the Area EPS Operator shall have the right to adjust the settings remotely in conformance with the Interconnection Agreement. If no communication channel exists, the DER Operator shall update settings and implement the changes within the time frame required by the Area EPS Operator once receiving the change request per the Area EPS Operator's established protocol defined in agreements or within the protocol defined in the Area EPS Operator's TSM. The timeframe required for the DER Operator to update settings and implement changes should not be shorter than three (3) Business Days. The type of settings change and the impact to the operation of the Area EPS should be considered in determining appropriate time for implementing settings. Failure to carry out a settings change within the applicable timeframe requested by the Area EPS Operator, may result in temporary disconnection of the DER if the inability to make the adjustment may affect safety, reliability or service quality. Nothing in this section precludes the Area EPS Operator's ability to immediately temporarily disconnect the DER for urgent operational needs at any time.

[15] The effectiveness of using reactive power control functions depends on the technical characteristics of the system including the send-out voltage, total line impedance, and X/R ratio.

[16] Categories A and B have different reactive power capability requirements, both require a percentage of the apparent power nameplate rating to be available for reactive power. Category B is capable of injecting or absorbing 44% of apparent power rating when active power output exceeds 20% of DER nameplate rating. Category A is capable of reactive power injection of 44% and absorption of 25% of nameplate apparent power when active power output exceeds 20% of DER nameplate rating. Both categories' reactive power requirements contain a gradient between 5% and 20% active power output levels. See section 5.2 of IEEE 1547 for additional details.

5.3 Voltage and Reactive Power Control

As defined by IEEE 1547 Clause 5.3.1, the Area EPS Operator specifies a reactive power control mode. Unless otherwise specified in the Area EPS Operator's TSM or specified in the Interconnection Agreement, the DER shall be installed with constant power factor mode enabled with 0.98 power factor, absorbing reactive power.

5.4 Voltage and Active Power Control (volt-watt)

Unless otherwise specified by the Area EPS Operator's TSM or in the Interconnection Agreement, the DER shall operate with the voltage-active power function enabled with the following default settings[17].

Table 3. Voltage-Active Power Setting for Category A and Category B DER

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

[a] P_{min} is the minimum active power output in p.u. of the DER rating.

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

[c] Any setting for the open loop response time of less than 3 seconds shall be approved by the Area EPS Operator with due consideration of system dynamic oscillatory behavior.

The voltage-active power function may reduce DER energy production during times of abnormally high voltage. The extent of that reduction of production is dependent on the specific setting of the function, as well as actual steady-state voltage observed over time at the DER location. Deviation in the voltage parameters settings from the default, such as setting a voltage parameter to a lower value, may exacerbate the possible energy production reduction.

In the circumstance where a DER Operator's production is being impacted by the Area EPS voltage, the DER Operator should notify the Area EPS Operator of the voltage concern[18]. The Area EPS Operator shall investigate the cause of abnormal voltage. If the abnormal voltage is

[17] The default IEEE 1547 volt-watt default setting will not begin curtailing real power until the voltage is beyond 1.06 per unit voltage, which is the upper end of the range of normal voltages allowed under ANSI C84.1.

[18] For example, DER with the PCC located near the substation with a high source voltage may require upward adjustment of the V_1 parameter to avoid significant production impacts.

originating from the Area EPS, the Area EPS Operator may need to modify equipment or settings. The Area EPS Operator may also need to work with other electric services to bring voltage within ANSI C84.1 Range A. If the abnormal voltage is originating from the DER Operator's premise, the DER Operator is responsible for mitigating the root cause.[19]

The default in IEEE 1547 is to disable voltage-active power function. The TIIR requirement may necessitate a settings change from the default settings that DER equipment may contain when shipped from a manufacturer.

6. Response to Abnormal Conditions

6.1 Introduction

Abnormal conditions can arise on the Area EPS, TPS or BPS, for which the DER shall appropriately respond based on the performance category assigned, required settings, and the requirements in IEEE 1547. The abnormal performance capabilities are intended to support wide area and localized system stability. The Minnesota statewide default parameters for DER response to abnormal conditions shall not materially impact safety, reliability, or the Area EPS Operator's ability to operate the Area EPS.[20]

6.2 Voltage Ride-Through and Tripping

The DER shall conform to the ride-through requirements for the applicable Abnormal Operating Performance Category. The IEEE 1547 default parameters shall be implemented by the DER Operator for the applicable performance category, unless otherwise specified by the Area EPS Operator's TSM. The RTO may provide guidance on mandatory ride-through capabilities.

Until the Regional Transmission Operator determines the setting for mandatory tripping, the Table 4 and Table 5 shall be used.

[19] All parties should attempt, with a good-faith effort, to resolve voltage concerns in the process identified in TIIR Section 5.3. Any voltage concern disputes not resolved are to follow the dispute resolution process in MN DIP Section 5.3 and MN DIA Article 10.

[20] The Area EPS Operators of Minnesota strive to be included in any efforts by the appropriate entities' Independent System Operator seeking to impose default parameter values on DER that differ from IEEE 1547. The process of determining new statewide or regional abnormal response parameter defaults that deviate from national standard default values should only be the outcome of a broad consensus process.

Table 4. DER Response (shall trip) to Abnormal Voltages for DER of Abnormal Operating Performance Category I

Shall Trip – Category I		
Shall Trip Function	**Default Setting[a]**	
	Clearing time (s)	**Voltage (p.u. of nominal voltage)**
UV2	0.16	0.45
UV1	2.0	0.7
OV1	2.0	1.10
OV2	0.16	1.20

Table 5. DER Response (shall trip) to Abnormal Voltages for DER of Abnormal Operating performance Category II

Shall Trip – Category II		
Shall Trip Function	**Default Setting[a]**	
	Clearing time (s)	**Voltage (p.u. of nominal voltage)**
UV2	0.16	0.45
UV1	10.0	0.70
OV1	2.0	1.10
OV2	0.16	1.20

Notes for Table 4 and 5
[a]The Area EPS Operator may specify other voltages and clearing time trip settings within the range of allowable settings, e.g. to consider Area EPS protection schemes.

A. Modifications to the Permissive Operating Capability Region

Momentary Cessation may be required for a portion of the Permissive Operating Capability Region. Consult the Area EPS Operator's TSM for further details.

6.3 Frequency Ride-Through and Tripping

The DER shall conform to the ride-through requirements for the applicable Abnormal Operating Performance Category. The IEEE 1547 default parameters shall be implemented by the DER Operator for the applicable performance category. The RTO may provide guidance on mandatory ride-through capabilities.

Until the RTO provides guidance the settings for mandatory tripping, Table 6 shall be followed.

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

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

Notes for Table 6
[a]The frequency and clearing time set points shall be field adjustable. The actual applied under-frequency (UF) and over-frequency (OF) trip settings shall be specified by the Area EPS Operator in coordination with the requirements of the regional reliability coordinator. If the Area EPS Operator does not specify any settings, the default settings shall be used.

The DER shall conform to the Rate of Change of Frequency (ROCOF) ride-through requirements for the applicable Abnormal Operating Performance Categories. The IEEE 1547 values shown in Table 7 shall be implemented by the DER Operator for the applicable performance category.

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

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

The DER shall conform to the frequency-droop requirements for the applicable Abnormal Operating Performance Categories. The IEEE 1547 values shown in Table 8 shall be implemented by the DER Operator for the applicable performance category.

Table 8. Parameters of Frequency-Droop (Frequency-Power) Operation for Abnormal Operating Performance Category I and Category II

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

Notes for Table 8
[a]Adjustments shall be permitted in coordination with the Area EPS operator.

6.4 Exceptions

Tripping or intentional islanding as an alternative to ride-through is allowed in specific situations (such as when a large load is on premise) which may modify the DER response to abnormal conditions. Refer to IEEE 1547 Section 6.4.2.1 and 6.5.2.1 for additional details.

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

6.5 Dynamic Voltage Support

Dynamic voltage support may be required. Consult the Area EPS Operator's TSM for further details.

7. Protection Requirements

7.1 Introduction

The DER shall be designed with proper protective devices to respond to faults and abnormal conditions in accordance with applicable standards including IEEE 1547 and parameters defined by this document or the Area EPS Operator's TSM.

7.2 Requirements

Details of each Area EPS Operator's protection requirements shall be found in the Area EPS Operator's TSM. As specified by Area EPS Operator's TSM, an AC disconnect furnished by the DER Operator may be required for Area EPS Operator's personnel to safely isolate the DER from the Area EPS. If required, the AC disconnect shall provide a visible air-gap, shall be lockable, and accessible to Area EPS Operator's personnel to safely isolate the DER from the Area EPS.[21]

All equipment providing relay functions shall meet or exceed ANSI/IEEE Standards for protective relays, or standards applicable for the installation voltage, unless otherwise specified by the Area EPS Operator's TSM.[22] Other requirements associated with protection and instrument transformer application may be specified by the Area EPS Operator.

7.3 Response to Faults and Open Phase Conditions

The DER shall Cease to Energize and Trip for faults on the Area EPS. The DER shall detect and Cease to Energize and Trip all phases to which the DER is connected for an open phase condition 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, the DER shall detect and Cease to Energize and Trip 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.

7.4 Additional Protection

Additional protection may be required as part of the Area EPS's Interconnection Facilities to limit Area EPS exposure to reliability impacts.[23] Other circumstances, such as low voltage secondary network interconnections, may require additional protection associated with the Area EPS's Interconnection Facilities.

In general, an increased degree of protection is required for increased DER size. Medium and large DER installations may require more sensitive and faster protection to minimize

[21] In some cases, the NEC required device for rapid shutdown for inverter-based DER may meet the Area EPS Operator's requirement for an AC disconnect if it provides a visual air-gap.
[22] Inverters certified to UL 1741 may contain protective functions that do not require equivalent external protective relays to meet IEEE 1547 requirements.
[23] For example, additional layers of protection may be required if the Area EPS's Interconnection Facilities lead to significant line exposure.

potential damage and ensure safety.[24] The addition of a new DER in conjunction with the aggregate of the existing DER systems may also affect the ability of existing protection schemes to function, which may require modification to the Area EPS's protection equipment.

8. Metering

8.1 Introduction

The Area EPS Operator shall specify metering requirements in the Area EPS Operator's TSM. Information about the DER's present and historic operating characteristics may be required by the Area EPS Operator in order to plan and operate the system. In addition, information may be needed to fulfill financial and regulatory obligations associated with DER energy production.

The different types of data may have different requirements in terms of accuracy and granularity, which should be considered by the Area EPS Operator. The information required for a given DER size may change as DER penetration increases on a portion of the Area EPS. Furthermore, each utility uses different metering technology that changes over time, each with its own integration considerations. Defining static metering requirements is a challenge. It is beyond the scope of this document to describe all of the potential different metering configurations or requirements. In general, the Area EPS Operator shall consider the following types of information when developing metering requirements in its TSM:

i. Operational – near-real-time information on the DER operating characteristics can be needed in order to perform certain actions such as reconfiguring a feeder or restoring a feeder after an outage.
ii. Planning – an archive of time-series information over multiple years of DER operation is required for Area EPS, BPS and TPS planning.
iii. Regulatory – The Area EPS Operator may have obligations to track and report on the amount of energy produced from renewable energy DER[25]. Specific incentive programs or tariffs can create additional metering needs.
iv. Billing – the Area EPS Operator is responsible for accounting for energy transactions with the DER Operator and shall have access to revenue grade metering information.

The Area EPS Operator may require separate accounting of generation and load power injection and consumption characteristics in order to meet planning and operating objectives on the Area EPS and TPS. Correlation of time data may be necessary in certain situations[26] and the Area EPS Operator should consider this factor when specifying metering requirements in its TSM. The Area EPS Operator may use other means of collecting the necessary information, besides the meter, if the Area EPS Operator determines the information is adequate for the intended use based on industry standards and best practices.

[24] Ride-through capabilities for bulk power system support should be considered before setting protective tripping times that conflict with BPS support.

[25] Renewable energy credits for certain Area EPS Operator tariffs is an example of reasons to track energy production.

[26] For example, where a time of use tariff exists and multiple meters are present, the time intervals of meters need to be time synchronized in order for the Area EPS Operator to properly execute its tariffed obligations. Another example would be a planning need where data has to be synchronized in time.

8.2 Requirements

The DER installation shall include metering provisions based on the interconnection characteristics and requirements. Each Area EPS Operator shall specify requirements in their TSM.

9. Interoperability

9.1 Introduction

The IEEE 1547 standard requires the capability to provide a Local DER Communication Interface, which is the basis for interoperability requirements. The Local DER Communication Interface may be used to exchange standardized information with the Area EPS Operator. The exchange of information allows the Area EPS Operator to perform monitoring and control functions necessary to the safe and reliable operation of the Area EPS.

Per IEEE 1547 Section 10.1, the decision to use the Local DER Communication Interface or to deploy a communications network is determined by the Area EPS Operator. Given existing and future DER integration needs, as well as the differences amongst various Area EPS Operator's systems, no uniform set of standards is defined in this document for requiring use of the Local DER Communication Interface. The factors included in an Area EPS Operator's decision to use the Local DER Communication Interface shall be provided in the Area EPS Operator's TSM.

For DER where a standard Local DER Communication Interface is not used upon initial installation, future Area EPS, TPS, or BPS conditions may arise that trigger a need to begin using the Local DER Communication Interface. The DER Operator shall constructively participate in evaluating feasibility of establishing use of the Local DER Communication Interface if needed due to considerations for integrating DER with an Area EPS. Any modifications to utilize the Local DER Communication Interface for existing interconnected DER systems shall be established by mutual agreement between the Area EPS Operator and the DER Operator.

DER systems designated by authority having jurisdiction as emergency, legally required, or critical operations power systems providing backup power to hospitals, fire stations or other emergency facilities as defined by applicable industry code, may be exempt from the interoperability requirements of this section. Additional details are listed in the Area EPS Operator TSM.[27]

9.2 Monitoring, Control and Information Exchange

When information exchange through the Local DER Communication Interface is required by the Area EPS Operator, the IEEE 1547 interoperability parameters shall be available for use. The Area EPS Operator shall have read access to all parameters in the nameplate information and monitoring information. The Area EPS Operator shall have read and write access to all parameters in configuration information and management information. The Area EPS

[27] IEEE 1547 does allow exemption in capabilities that the Area EPS operator may require in certain situation.

Operator may choose to use a subset of the available parameters in order to meet operating objectives of safe, reliable, and quality electric service. Writing of information by the Area EPS Operator through the Local DER Communication Interface, shall follow agreements governing Area EPS Operator control of the DER operating state control modes and parameters.

When the Local DER Communication Interface is required by the Area EPS, the Area EPS shall have access to read and write parameters shown in the sub clauses associated with IEEE 1547, Section 4.6 – *Control capability requirements* – including capability to disable permit to service; capability to limit active power; and execution of mode and parameter changes.

9.3 Communications

When communication is required to the DER and/or the applicable meter(s), the DER Operator may be responsible for furnishing the communication channel from the Area EPS Operator's applicable system(s) to the DER and/or the meters. The form of communication (Cellular, Radio, etc.) shall be determined by the Area EPS Operator. Additional details of communication requirements shall be specified in the Area EPS Operator's TSM. Communication performance requirements, such as latency of exchanged information, periodicity, reliability of communication channels, and volumes of data, may be defined by the Area EPS Operator's TSM or in an operating agreement.

9.4 Cyber Security

The local physical and network security requirements specified by the Area EPS Operator shall be implemented by the DER Operator. The Area EPS should consider the degree of risk associated with various DER technology and application in determining the cyber security requirements. The Area EPS Operator shall outline cyber security requirement with respect to DER in its TSM.

Communications circuits tied to monitoring and control systems associated with Area Electric Power System (EPS) real-time operations shall meet security and reliability requirements as defined by the Area EPS Operator, industry standards, and appropriate regulating authorities.

A. DER Physical and Front Panel Security

The DER Operator shall provide a reasonable level of security for the DER controls and devices from operation by intruders. The Area EPS Operator may specify additional physical security requirements in its TSM.

B. DER Network Security

The network security requirements and implementation details may differ among Area EPS Operators and are expected to evolve over time in order to maintain cyber security in an environment of constantly changing cyber threats. The network security requirements for the DER Operator may be described in each Area EPS Operator's TSM.

C. Local DER Communication Interface Security

When information is exchanged through the Local DER Communication Interface, consideration should be given to protect access to information. Numerous system architecture approaches and technologies exist for securing the interface. The Area EPS Operator may specify security requirements associated with the Local DER Communication Interface. Where practical, test and verification procedures shall be specified for local DER communication interface security.

10. Energy Storage

10.1 Introduction

An Energy Storage System (ESS) operated in parallel with the Area EPS is a DER subject to the standard applicable reviews and requirements for a DER acting as a generation source (ESS discharging). Additional review is required for unique features of ESS, when compared to other DER, such as the load (ESS charging) aspects and ESS Control Mode(s). The Area EPS Operator should perform the appropriate technical review and study of all aspects of ESS during the appropriate step in the Minnesota Interconnection Process. Power Control characteristics may simplify the review process, since ESS is often inverter-based and ongoing reverse power flow may not be anticipated, but a standard review shall be completed since the potential exists for voltage, thermal, and protection impacts.

Interconnection of ESS in a parallel configuration often requires consideration of compatibility with applicable tariffs. ESS interconnection or operational requirements may result from a customer's choice of DER tariff[28] or load service tariff.

Application of the Minnesota DER TIIR shall not constrain adoption of national standards and best practices as they are developed. The ESS-specific aspects of DER interconnection standards are expected to receive an increased focus from industry standards associations in upcoming years[29], with resulting ESS standards publications at a quicker pace.

The absence of guidance on ESS best practices and standards at a national level makes it likely that this section will require future revision sooner than other sections in the document. The intent of this document is to adopt standards as they become available. The approach taken for ESS in the TIIR is to define functional requirements, leaving implementation, testing, and verification for definition in individual Area EPS Operator's TSM. As was the case with inverter-based DER prior to IEEE 1547 in 2003, the types and use cases associated with ESS will continue to rapidly shift until standards and certifications are developed. Based on these factors, the Area EPS Operator shall specify any additional ESS requirements in the Area EPS Operator's TSM.

[28] For example, a tariff rate associated with a Qualifying Facility (QF), as defined in federal law and often relied upon in net metering rate definitions of eligible energy resources, requires all energy exported to the Area EPS to be from a QF. For ESS to be considered a QF, all of the energy charging ESS must originate from a different DER which meets the QF definition.

[29] At the time the TIIR are being written, certifications, national standards, guides, and recommended practices governing the capabilities and performance of ESS are yet to be written or published.

10.2 ESS Control Modes

Changes in ESS Control Modes to a mode that was not proposed and reviewed during the interconnection process can result in tariff violations or cause adverse technical impacts to the Area EPS. ESS Control Modes may not necessarily be considered a Material Modification, however the Interconnection Customer shall notify the Area EPS Operator of an unapproved ESS Control Mode prior to the change being implemented. The Area EPS Operator shall discuss with the Interconnection Customer the need, or lack thereof, to review the proposed ESS Control Mode for safety, power quality or reliability reasons.
IEEE 1547 states that a functional software or firmware change may result in another verification process at that time of interconnection and interoperability requirements. The IEEE 1547 standard, and other national standards and certifications, are currently silent on requirements relating to ESS Control Mode definition, implementation (i.e. default responses and ranges of allowable settings), transition between modes, adding new modes after initial interconnection, and all associated testing and verification procedures. Until industry standards and certifications are developed to address these aspects of ESS, a significant gap exists for which a grouping of partial solutions may be required by the Area EPS Operator, including, but not limited to the following requirements:

i. Documenting at the time of application the ESS Control Modes being applied for by the ESS owner. This information may be collected through an Area EPS Operator specific document[30] or the Area EPS Operator's online application portal.
ii. Documenting at the time of application the charge/discharge profile(s) or use case(s) intended to be utilized by the ESS owner. This information may be collected through an Area EPS Operator specific document or the Area EPS Operator's online application portal.
iii. The ESS Control Mode(s) reviewed and approved should be documented in an Operating Agreement. The Operating Agreement should also list the ESS Control Mode(s) that is being utilized. Area EPS Operator shall be notified of changes to ESS Control Mode(s). The changes and notification to the Area EPS Operator shall follow all applicable agreements and requirements as documented in the TSM.
iv. A method of ESS Control Modes security shall be furnished by the DER Operator to assure only ESS Control Modes applied for and reviewed by the Area EPS Operator are used. The security may be in the form of password protection of the functions or other methods specified by the Area EPS Operator's TSM.
v. Operation of the ESS shall be compatible with applicable tariffs[31], as required by the Area EPS Operator standard implementation of the tariffs.
vi. The Area EPS Operator may initiate verification of the ESS operation after the interconnection is complete if information is available indicating the ESS is not functioning as designed or approved.

[30] Upon publication of standards and certifications, this type of information will be well-suited to be included in statewide interconnection process documentation. Until that time, it is likely the type of ESS information needed could rapidly shift, depending on customer preferences and available technology. Continual shifts in technology, application of technology, and market place are occurring at a rapid pace at the time the TIIR is being written.
[31] Definitions of non-exporting and inadvertent export in statewide standards clarifies implementation of certain tariffs for ESS.

10.3 ESS Load Aspects

The load impacts of ESS shall be considered in scope for the statewide TIIR. The load aspects of ESS are not in scope of the IEEE 1547 standard, but reviewing the load aspects in conjunction with generation aspects is crucial to evaluating impacts to the Area EPS and leads to a more efficient review of the overall system. Impacts from ESS may contribute to requirements and mitigations, including but not limited to: electrical component upgrades; information exchange through use of the Local DER Communication Interface; or protection and control system upgrades.
Any Area EPS Operator's operating characteristics requirements for ESS charging operations shall not be more restrictive than the operating characteristics requirements of other comparable loads, to the extent practical or upon mutual agreement. The maximum charge rate of the ESS shall be included in materials submitted to the Area EPS Operator during the technical review portion of the interconnection process.

Certain grid events[32] may cause a large number of ESS in the affected area to simultaneous respond. Any future changes to wholesale markets allowing ESS to participate could also introduce unintentional wide-area ESS simultaneous response and impacts not accounted for during the interconnection process. Interconnection reviews typically do not contemplate this type of group response. The Area EPS Operator may define in the TSM interconnection technical requirements to address impacts from conditions where multiple unrelated ESS on a portion of the Area EPS are operating in concert.

11. Power Control Limiting – Capacity, Export, and Import

11.1 Introduction

The DER Operator 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 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 Area EPS Operator[33].

[32] For example, an extended outage could cause all the impacted ESS charge to largely deplete, which could trigger charging of all the effected ESS when power is restored on the Area EPS. The resulting charging could result in unanticipated overloads on the Area EPS unless the condition has been studied.

[33] MN DIP Section 5.14.3 states "the Interconnection Customer must obtain the Area EPS Operator's agreement that the manner in which the Interconnection Customer proposes to implement such a limit will effectively limit active power output so as to not adversely affect the safety and reliability of the Area EPS Operator's system."

11.2 Power Control Limited Capacity

Using Area EPS Operator's approved Power Control methods, the DER Operator may limit the DER AC capacity. The limited DER AC capacity value may be used by the Area EPS Operator when performing impact studies if the means of limiting capacity is determined to be adequate by mutual agreement. Some of the reasons the DER Operator may choose to limit DER AC capacity include, to avoid system upgrades or to size the DER to be compatible with programs or tariffs[34].

For inverter-based DER systems 20 kW or less in Nameplate Rating, the Power Control limited capacity shall be implemented through utilizing the IEEE 1547 configuration settings[35]. For Power Control capacity limiting, active power limits at unity and non-unity power factors may be applied. The DER Operator shall propose the configuration settings to the Area EPS Operator for review and approval.

For rotating machines or inverter-based DER systems larger than 20 kW in Nameplate Rating, the DER Operator shall submit details of the proposed Power Control limiting method for maximum capacity limiting, along with settings, if applicable. The Area EPS Operator shall review and either approve the proposed Power Control method and settings or provide a response as to why the method does not provide adequate control. The DER system should use the IEEE 1547 configuration settings as the preferred means of Power Control limited capacity.

11.3 Power Control Limited Export and Power Control Limited Import

Power Control limited export and Power Control limited import can provide means of meeting the requirements of specific Area EPS Operator's tariffs or other technical requirements. The DER Operator shall obtain approval from the Area EPS Operator for any Power Control limiting system which is implemented. Power Control limiting for inverter-based DER systems with a Nameplate Rating of 20kW or less shall use a certified control system tested to UL 1741[36]. For these smaller systems, the DER Owner shall submit proposed settings to the Area EPS Operator for review and approval. For DER systems with a Nameplate Rating larger than 20 kW using a certified control system tested to UL 1741, the DER Operator shall provide test results showing the magnitude and duration of power import or export.

The Power Control limited export and import may be applied using a UL 1741 certified Power Control System to limit import or export. Additionally, Power Control limited export may be applied using the IEEE 1547 *maximum active power* parameter to limit export in the

[34] The applicable programs or tariffs eligibility may be based on a nameplate capacity rather than a configured value. Consult the tariff or program rules of interest to determine if the nameplate capacity governs any aspects of the interconnection.
[35] IEEE 1547 Table 28 Nameplate Information contains the available configuration parameters which may be altered as allowed by Section 10.4.
[36] Testing to the UL Certification Requirement Decision on Power Control Systems may be used in the interim.

management settings[37] in cases where the RPA is at the PCC. The *maximum active power* parameter in the DER management information shall be used as a static limit when employed for limiting export. Similarly, the Power Control System import or export limit shall be a static limit when employed for limiting export or limiting import.
The current approved standards-based approaches for Power Control limiting have a maximum open loop response time limit of 30 seconds for limiting inadvertent active power exchange with the Area EPS. Active power exchange may occur for a period of time within this 30 second limit due to Local EPS conditions such as block load changes. Reactive power exchange between the DER, Local EPS and the Area EPS may occur during normal operations, but level and amount of this exchange shall be in accordance with applicable agreements.

The configuration and settings governing the Power Control limiting functions shall be password protected, accessible only by qualified personnel, or protected by other means which have been approved by the Area EPS Operator.

11.4 Other Power Control Methods

While this technical document has attempted to provide guidance and standards for Power Control limiting methods, this is a new and quickly changing area. This technical standard shall not preclude alternate means of Power Control limiting which may be implemented by mutual agreement between the DER Operator and the Area EPS Operator. The DER Operator shall provide details to the Area EPS Operator for any proposed Power Control limiting function. The proposal shall include settings, equipment information, and any other information necessary for the Area EPS Operator to complete a review of the proposal. Non-export limitations based on relaying or load characteristics are examples of potential proposals from a DER Operator. It is recommended that the DER Operator consider using a standards-based Power Control limiting system prior to proposing alternate solutions.

12. Enter Service and Synchronization

When entering service, the DER shall not energize the Area EPS until voltage and system frequency are within the ranges specified in Table 9 or established by Area EPS Operator's TSM.

Table 9 Enter Service Voltage and Frequency Criteria

Enter Service Criteria		**Default Settings**
Applicable voltage within range	Minimum value	$\geq$ 0.917 p.u.
	Maximum value	$\leq$ 1.05 p.u.
Frequency within range	Minimum value	$\geq$ 59.5 Hz
	Maximum value	$\leq$ 60.1 Hz

[37] IEEE 1547 Section 4.6.2 allows for an active power limit to be set as an export limit when the RPA is the PCC. The parameter is found in Table 40 of IEEE 1547 Section 10.6.12.

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

13. Intentional Islanding

As an alternative to cease to energize and trip in response to voltage or frequency disturbances or unintentional island detection, a Local EPS island may be formed. When DER meets the criteria of Section 6.4, a Local EPS island may be formed rather than ride-through for voltage or frequency disturbances. If DER does not meet the criteria of section 6.4, the transition to the Local EPS island shall meet the rapid voltage change requirements of IEEE 1547. When paralleling a Local EPS island to the Area EPS, the Enter Service and Synchronization requirements of Section 12 shall be met.

DER systems designated by authority having jurisdiction as emergency, legally required, or critical operations power systems providing backup power to hospitals, fire stations or other emergency facilities as defined by applicable industry code, shall be exempt from this section and may Cease to Energize and Trip or separate from the Area EPS without limitation. Scheduled intentional Local EPS islands are allowed in accordance with IEEE 1547 Section 8.2.2 and applicable agreements.

Intentional Area EPS islands shall only be allowed upon mutual agreement between the Area EPS Operator and DER Operator.

14. Test and Verification Requirements

14.1 Introduction

Prior to a DER system's initial interconnection or operation in parallel with the Area EPS, the Area EPS Operator may require verification and testing of the DER interconnection. The Area EPS Operator's TSM document is expected to be reviewed to understand the interconnection testing requirements. The testing of the DER shall depend upon the type, size and complexity of the DER system. For DER systems utilizing certified inverters, which meet the IEEE 1547 interconnection requirements, the testing shall be to confirm the proper installation and configuration of the equipment.

Type tests and conformance testing are related to the interconnection requirements and safety aspects. The operational compliance with applicable tariffs, which is often pertinent for storage, is not affirmed through the test and verification requirements outlined in this section.

The process associated with design, approval and execution of test and verification procedures follows:

- The Area EPS Operator shall define the characteristics of tests that are required by applying standards and best practices.
- The RPA shall be specified in the one-line diagram submitted to the Area EPS Operator with the Interconnection Application. The DER Operator shall denote the RPA where

the test and verification feature shall be applied in the written test procedure, if required.

- When required by the Area EPS Operator, the DER Operator shall provide written test procedure to the Area EPS Operator for review.
- The testing and verification procedures shall be reviewed and approved by a Professional Engineer when a Professional Engineer is required for design of the DER as specified by the MN DIP[38].
- The Area EPS Operator shall provide written feedback to the DER Operator, if written test procedures are required, indicating the determination if the test and verification meets applicable requirements. Prior to witness testing, the Area EPS Operator may require the DER Operator to attest the DER system is ready for testing.[39]
- The Area EPS Operator and the DER Operator shall arrange for qualified personnel to perform the test procedures. Each entity shall operate their own equipment.
- The Area EPS Operator may arrange personnel to witness the test procedures being performed by the DER Operator.
- The Area EPS Operator may evaluate the DER as-built installation, including as outlined in IEEE 1547.1, during this site visit to verify that the installation meets interconnection and interoperability requirements.

The applicable DER evaluation, commissioning tests and verifications, shall be performed per IEEE 1547, IEEE 1547.1, and Area EPS Operator's TSM.

14.2 Full and Partial Conformance Testing and Verification

All DER used for interconnection with an Area EPS shall be tested to conform to IEEE 1547 interconnection requirements using IEEE 1547.1 conformance test procedures. Additional testing to affirm compliance with applicable tariffs may be outlined by the Area EPS Operator within their TSM. One way a DER shall be considered as conforming to IEEE 1547 is if it has been submitted by a manufacturer, tested and listed by an Occupational Safety and Health Administration (OSHA) Nationally Recognized Testing Laboratory (NRTL) for continuous grid interactive operation in compliance with the applicable codes and standards and is determined to be fully compliant. DER equipment shall be tested to conform to the IEEE 1547 requirements and listed in accordance with an OSHA NRTL.

All inverter-based DER units shall be UL 1741 certified. Certified DER equipment that do not require a supplemental DER device to meet IEEE 1547 requirements at the Reference Point of Applicability and where the impedance between the PCC and POC is less than 0.5% on the DER rated apparent power and voltage base shall be considered fully compliant. Partially compliant DER shall require further evaluation and possible testing. All DER systems shall meet the requirements of IEEE 1547 regardless of whether they are classified as fully or partially compliant.

[38] A Minnesota license Professional Engineer signature is required for certified system greater than 250 kW or for non-certified system greater than 50 kW as outlined in MN DIP 1.5.1.4.
[39] MN DIP Attachment C Certificate of Completion, is an example of certifying the DER system is ready for testing.

IEEE 1547 introduces the concepts of Reference Point of Applicability, which is located at either the PoC or the PCC. The IEEE 1547 standard section 4.2 should be referenced to determine the RPA, as the RPA is the point at which testing and verification requirements apply. Annex B in this document describes the relationship of these terms.

Figure 3 details the test and verification required steps when the RPA is at the PoC for a fully compliant DER Unit or DER system as well as a partially compliant composite DER system. Fully compliant DER Unit(s) require *basic* design evaluation and commissioning tests. Partially compliant DER Units(s) require *detailed* design evaluation. For example, a fully compliant DER Unit(s) with the RPA at the PoC is representative of a residential rooftop PV system. The DER Unit would be type tested by a NRTL resulting in a UL 1741 certification. IEEE 1547.1 details the Design Evaluation and Commissioning Test required for each of the combinations of fully and partially compliant DER with the RPA at the PoC and PCC.

Figure 3 Test and Verification Required Steps for RPA at PoC

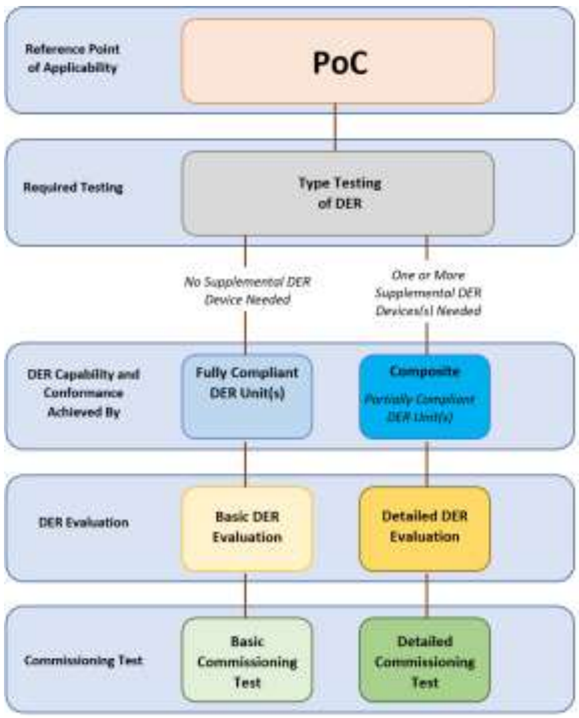
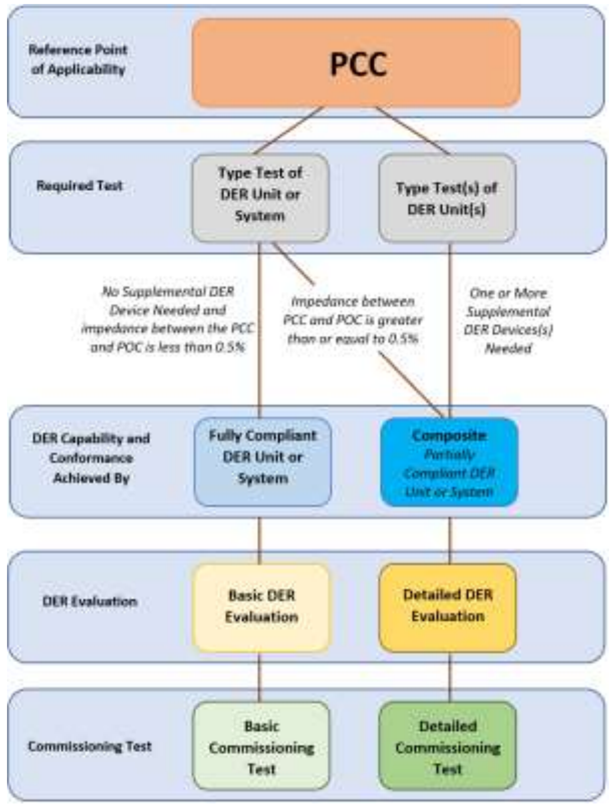


Figure 4 details test and verification requirements when the RPA is at the PCC. Requirements for fully compliant DER Units or systems and partially compliant DER Unit or systems are addressed separately in terms of required testing and evaluation.

Figure 4 Test and Verification Required Steps for RPA at PCC



14.3 Documentation

Testing and verification documentation requirements shall be specified in the Area EPS Operator's TSM. Fault current characterization information required in IEEE 1547, subclause 11.4, shall be provided to the Area EPS Operator upon request or per the Area EPS Operator's TSM.

14.4 Failure Protocol

In the event that a DER fails testing and verification, the DER Operator shall resolve any out-of-compliance items and resubmit or reschedule the appropriate items as defined by the MN DIP and Area EPS Operator's TSM.

14.5 Reverification and Periodic Tests

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

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

Prior to modifications to the DER triggering reverification, the DER Operator shall notify the Area EPS Operator's interconnection coordinator, as identified on the Area EPS Operator's website. Any of the above events may be cause for requiring reverification of the interconnection and interoperability requirements, per IEEE 1547 clause 11.2.6.

The Area EPS Operator may specify the frequency or time intervals for periodic testing consistent with Area EPS Operator's policies or manufacturer requirements.

14.6 Simplified Process Testing Procedure

The general process for field inspection and testing of an inverter-based DER that is less than 20 kW in size and approved through the Simplified Process, is outlined below. Specifics of the testing procedure and the responsibilities of the installer shall be identified in the Area EPS Operator's TSM.

General Process for Simplified Testing Procedures

- Verify installation matches design evaluation
  - Verify inverter model matches application
  - Verify certified inverter
  - Verify correct labeling / signage
  - Verify installation matches application one-line (i.e. connections, location of protection, disconnect switch, metering etc.)
  - Verify electrical inspection sticker
  - Verification of operational and protection settings

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

15. Operating and Maintenance Requirements

Operating and Maintenance Requirements may be required by the Area EPS Operator and are documented in Attachment 5 of the Interconnection Agreement.[40] The Operating and Maintenance Requirements are created for the benefit of both the DER Operator and the Area EPS Operator 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 DER Operator and the Area EPS Operator. There may also be changes required by external issues, such as changes in FERC and RTO recommendations or policies, which may require the updates to the Operating and Maintenance Requirements. Any updates to the Operating and Maintenance Requirements shall be agreed to between parties. In cases where mutual agreement cannot be achieved, see MN DIP section 5.3 and MN DIA Article 10.

[40] The Interconnection Agreement requirements are defined in the statewide Minnesota DER Interconnection Agreement (MN-DIA).

The following is a list of typical items that may be included as Operating Requirements. The items included as Operating Requirements shall not be limited to the items shown on this list:

i. Operational requirements, settings, and limits for DER when the Area EPS is in a normal condition
ii. Operational requirements, settings, and limits when the Area EPS is in an abnormal condition due to maintenance, contingencies, or other system issues
iii. Permitted and disallowed ESS Control Modes
iv. BPS or TPS limitations and arrangements that could impact DER operation
v. DER restoration of output or return to service settings and limitations
vi. Response to control or communication failures
vii. Performance category assignments (normal and abnormal)
viii. Dispatch characteristics of DER
ix. Notification process between DER Operator and Area EPS Operator
x. Right of Access

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

i. Routine maintenance requirements and definition of responsibilities
ii. Material modification of the DER that may impact the Area EPS

Annex A – Link to webpage containing Area EPS Operator Technical Specifications Manual (TSM)

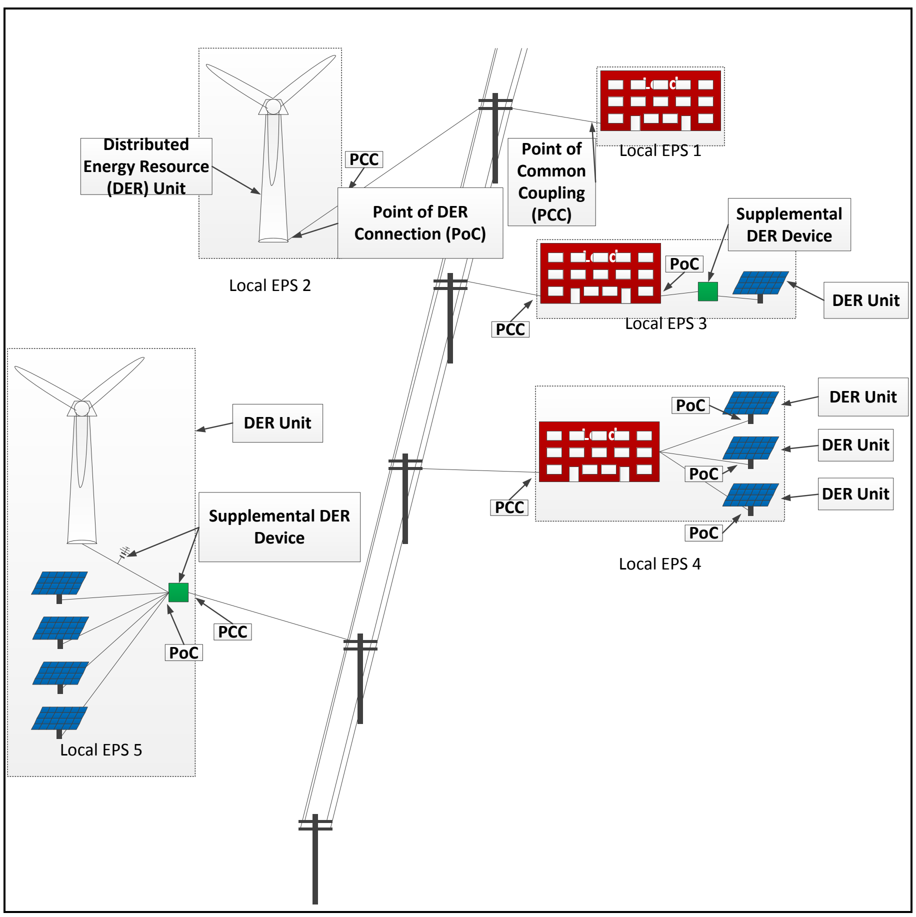
Below is the website address associated with an Area EPS Operator webpage containing the Operator’s TSM:

Company	Website Address
Dakota Electric Association	
Minnesota Power	
Otter Tail Power	
Xcel Energy – Northern States Power Minnesota	

Annex B – Clarification on Reference Point of Applicability, Point of Common Coupling, Point of DER Connection, and Supplemental DER Devices

The reference point of applicability (RPA) is the location where the requirements in IEEE 1547 and IEEE 1547.1 apply. The TIIR adopts the RPA as the location to apply technical requirements. The RPA is usually at the PCC or PoC. A location between the PoC and PCC can be mutually agreed upon as a substitute for when the location is determined to be at the PoC. The influence of load on the overall Local EPS operating characteristics is a driver behind the need for the RPA to be at the DER PoC. For example, meeting the reactive power requirement for DER may not be feasible if the DER is relatively small compared to a reactive power load in the same Local EPS. Similarly, ground referencing of the Local EPS also affects the ability of a DER to meet certain protection requirements. For example, detection of a loss-of-phase is not possible without zero-sequence continuity[41] between the Area EPS and Local EPS.

Decision trees for determining RPA are described in IEEE 1547, Section 4.2.



[41] For example, a transformer delta winding breaks zero-sequence continuity.

Annex C – Anticipated list of topics in a TSM

1	**Introduction**
2	**Abbreviations and Common Terms**
3	**Performance Category Assignment**
4	**Reactive Power Capability and Voltage/Power Control Performance**
5	**Response to Abnormal Conditions**
6	**Protection Requirements**
7	**Operations**
8	**Power Control Systems**
9	**Interoperability**
10	**Energy Storage Systems**
11	**Metering Requirements**
12	**Signage and Labeling**
13	**Test and Verification Requirements**
14	**Sample Documents for Simplified Process**
15	**Appendix**

Attachment 1

The following clarifies which sections of the TIIR go into effect immediately and which are replaced with an existing technical requirement until the Commission provides Notice that IEEE 1547-2018 certified equipment is readily available ("Commission Notice".)[1] The "interim period" referred to below is from July 1, 2020, the date the TIIR goes into interim effect, until the Commission Notice announcing the TIIR is in full effect.

All sections of the TIIR shall go into effect on July 1, 2020 except for the following sections for inverter-based systems. Mutual agreement between parties does allow for utilization of the full TIIR during the interim period.

Section 4 (Performance Categories)
This section does not go into effect until Commission Notice. No alternate provision is in place during the interim period.

Section 5 (Reactive Power Capability and Voltage/Power Control Performance)
Sections 5.4 does not go into effect until Commission Notice unless mutual agreement exists between parties. In the interim period, the power factor requirements of Section 5.3 shall be used as default settings[2].

Section 6 (Response to Abnormal Conditions)
This section does not go into effect until Commission Notice. In the interim period, the following tables shall be considered default settings unless mutual agreement between parties exists.

Table 1 - Synchronous DER Response (shall trip) to Abnormal Voltages

Shall Trip – Synchronous DER		
Shall Trip Function	Default Setting	
	Clearing time (s)	Voltage (p.u. of nominal voltage)
UV2	0.16	0.50
UV1	2.0	0.88
OV1	1.0	1.10
OV2	0.16	1.20

[1] MN PUC, ORDER 159427-01, Docket E-999/CI-16-521. Request input from the Technical Subgroup (TSG) of the Distributed Generation Workgroup (DGWG) as to when IEEE 1547-2018 certified equipment is "readily available" and delegate to the Executive Secretary the authority to notice when the full TIIR goes into effect in consultation with the TSG.

[2] IEEE 1547-2018 section 5.3.1, as referenced in the TIIR, does not apply in the interim period, but the constant power factor specification requirement can be applied.

Table 2 - Inverter DER Response (shall trip) to Abnormal Voltages

Shall Trip – Inverter DER		
Shall Trip Function	**Default Setting**	
	Clearing time (s)	**Voltage (p.u. of nominal voltage)**
UV2	0.16	0.50
UV1	2.0	0.88
OV1	1.0	1.10
OV2	0.16	1.20

Table 3 - DER Response (shall trip) to Abnormal Frequencies

Shall Trip Function	**Default Setting**	
	Clearing time (s)	**Frequency (Hz)**
UF1	0.16	59.3
OF1	0.16	60.5

Section 9 (Interoperability)
This section does not go into effect until Commission Notice. In the interim period, the Area EPS Operator's TSM shall be used. The Area EPS Operator's TSM shall contain Interoperability requirements comparable to section 5 (regarding metering and monitoring control requirements) of the 2004 State of Minnesota Distributed Generation Interconnection Requirements document.

Section 12 (Enter Service and Synchronization)
This section does not go into effect until Commission Notice. In the interim period, when entering service, the DER shall not energize the Area EPS until the applicable voltage and system frequency are within the ranges specified in Table 4,unless mutual agreement between parties exists.

Table 4 - DER Enter Service Criteria Ranges

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

DER shall be capable of delaying enter service by an intentional adjustable minimum delay when the Area EPS steady-state voltage and frequency are within the ranges specified in Table 4. The adjustable range of the minimum intentional delay shall be 0 s to 300 s with a default minimum delay of 300 s.

Section 14 (Test and Verification Requirements)
This section does not go into effect until Commission Notice. In the interim period, the Area EPS Operator's TSM shall be used. The Area EPS Operator's TSM shall contain Test and Verification requirements comparable to section 8 of the 2004 State of Minnesota Distributed Generation Interconnection Requirements document.

SECTION 6 CURTAILMENT OR INTERRUPTION OF SERVICE

6.1 REFUSAL OR DISCONTINUANCE OF SERVICE

With notice, the Company may refuse or discontinue service in accordance with the provisions of Minnesota Rules 7820.1000 through 7820.3000 and as described in Section 11. Any inconsistency between these tariff provisions and the rule provisions shall be resolved by applying the rule provisions for any of the following reasons: (1) failure to pay amounts payable when due, when the amount outstanding equals or exceeds the amount of the customer's deposit; (2) failure to meet the Company's deposit or credit requirements; (3) breach of contract for service; (4) failure to provide Company with reasonable access to its property or equipment; (5) failure to make proper application for service; (6) failure to comply with any of the Company's rules on file with the Public Utilities Commission; (7) if the customer has failed to furnish service equipment, and/or rights-of-way necessary to serve the customer as specified by the Company as a condition of service; (8) when necessary to comply with any order or request of any governmental authority having jurisdiction; and (9) when determined by the Public Utilities Commission as prescribed by relevant state or other applicable standards. T

Upon such notice as is reasonable under the circumstances, the Company may temporarily discontinue electric service when necessary to make repairs, replacements, or changes in the Company's equipment or facilities.

Without notice, the Company may disconnect electric service to any customer: (1) for unauthorized use or if the customer has tampered with the Company's equipment; or (2) in the event a condition appears to be hazardous to the customer, to other customers, to the Company's equipment, or to the public. Any discontinuance of electric service will not relieve the customer from customer's obligations to the Company.

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6.2 CURTAILMENT OR INTERRUPTION OF SUPPLY

Without notice, Company may curtail or interrupt service to any or all of its customers when in its judgment such curtailment or interruption will tend to prevent or alleviate a threat to the integrity of its power supply. In such event the judgment of the Company will be deemed conclusive on all parties involved. The selection by the Company of the customers to be curtailed or interrupted will also be conclusive on all parties concerned, and the Company will be under no liability for any such curtailment or interruption. Any curtailment or interruption of supply will not relieve the customer's obligations to the Company.

CERTIFICATE OF SERVICE

I, Mustafa Adam, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota; or

xx by electronic filing.

Docket No.: E002/C-20-892

Dated this 2nd day of March 2021.

/s/

Mustafa Adam
Regulatory Administrator

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_20-892_20-892
James	Denniston	james.r.denniston@xcelenergy.com	Xcel Energy Services, Inc.	414 Nicollet Mall, 401-8 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_20-892_20-892
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_20-892_20-892
Dean	Leischow	dean@sunrisenrg.com	Sunrise Energy Ventures	315 Manitoba Ave Wayzata, MN 55391	Electronic Service	Yes	OFF_SL_20-892_20-892
Matthew	Melewski	matthew@theboutiquefirm.com	Nokomis Energy	2639 Nicollet Ave., Suite 200 Minneapolis, Minnesota 55408	Electronic Service	No	OFF_SL_20-892_20-892
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_20-892_20-892
Angie	Schreiner	angie@sunrisenrg.com	Sunrise Energy Ventures, LLC	315 Manitoba Avenue Suite 200 Wayzata, MN 55391	Electronic Service	Yes	OFF_SL_20-892_20-892
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_20-892_20-892
Sky	Stanfield	stanfield@smwlaw.com	Shute, Mihaly & Weinberger	396 Hayes Street San Francisco, CA 94102	Electronic Service	No	OFF_SL_20-892_20-892
Lynnette	Sweet	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_20-892_20-892

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Peter	Teigland	pteigland@mnseia.org	MnSEIA	2288 University Ave. W. St. Paul, MN 55114	Electronic Service	No	OFF_SL_20-892_20-892
Joseph	Tierney	joe@sunrisenrg.com	Sunrise Energy Ventures	315 Manitoba Ave Wayzata, MN 55391	Electronic Service	Yes	OFF_SL_20-892_20-892
Curtis	Zaun	curtis@cpzlaw.com		3254 Rice Street Little Canada, MN 55126	Electronic Service	Yes	OFF_SL_20-892_20-892