GREEN MOUNTAIN POWER

INTERCONNECTION GUIDELINES

For Distributed Energy Resources

This document provides the basis for Green Mountain Power's technical review of proposed distributed energy resources, gives the requirements for interconnection to the Company's distribution power system, and provides assistance to customers to meet these requirements.

Effective March 22, 2021

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Table of Contents

1 Purpose

1. This Distributed Energy Resource Interconnection Guideline (Interconnection Guideline) covers requirements for interconnecting customers (Customer) proposing to install, for parallel operation, a Distributed Energy Resource (DER) system to Green Mountain Power's (GMP or the Company) distribution electric power system (EPS) for State jurisdictional projects under Vermont Public Utility Commission (VT PUC) Rule 5.100 and 5.500.
2. This Interconnection Guideline does not cover the technical federal and state transmission operator jurisdictional requirements (ISO-NE and FERC) for connection to the Company's transmission EPS.
3. This Interconnection Guideline is for interconnecting DER and provides general technical requirements, recommendations, and assistance to Customers regarding DER systems connected in parallel to the Company's distribution EPS. Each DER interconnection project is evaluated relative to its unique technical and engineering parameters. **As such, the Company reserves the right to amend or revise the technical requirements of this document, should it be justified by a project's unique circumstances or in the sole judgment of GMP is required to protect the safety of Company personnel and the public, or is required to protect the reliability of the EPS or customers' equipment.**
4. This Interconnection Guideline is available from the Company's website at

https://greenmountainpower.com/help/net-metering-project-requirements-process/

2 Scope

1. This Interconnection Guideline forms the basis for the Company's technical review of proposed DER, provides the requirements for interconnection to the Company's EPS, and provides assistance to Customers desiring to interconnect a DER to the Company's EPS.
2. This Interconnection Guideline is limited and applies to DER proposed for interconnection under VT PUC Rule 5.100 or Rule 5.500. For FERC jurisdictional projects connected to the Company distribution EPS, the technical provisions of this document also apply.
3. These requirements may also be applied, at the discretion of the Company, to other methods used to generate electricity in parallel with the Company's EPS.

3 Applicable Codes, Standards, and Guidelines

The Customer's DER facility shall conform to the latest revision of all local, state and federal codes and national standards that apply including issued amendments, unless the Company has taken exception to such standard. Specific codes and standards applicable to this Interconnection Guideline include, but are not limited to:

1. Institute of Electrical and Electronics Engineers (IEEE) Std. 1547 "Standard for Distributed Resources Interconnected with Electric Power Systems"
2. Underwriters Laboratories (UL) Std. 1741 "Inverters, Converters and Charge Controllers for Use in Independent Power Systems"
3. ANSI/IEEE C2 "National Electrical Safety Code®" (NESC)
4. NFPA 70 "National Electrical Code" (NEC)
5. NFPA 70B "Recommended Practice for Electrical Equipment Maintenance"
6. NFPA 70E "Standard for Electrical Safety in the Workplace"
7. NETA-MTS "Maintenance Testing Specifications for Electrical Power Distribution Equipment and Systems"
8. The Customer's DER facility shall also conform to any applicable requirements of PUC Rule 5.100 and Rule 5.500 and any local, state, federal and/or other agencies from which a review, approval, or a permit is required.
9. The Customer shall comply with appropriate Company tariff requirements, which cover details for the Customer's electric service installation.

4 Definitions and Acronyms

4.1 Definitions

1. **Certified:** Equipment that is approved, identified, labeled, and/or listed, by examination for safety; see NEC Articles 90 and 110.
2. **Certified DER:** An inverter Certified to the requirements of UL 1741 SA (September 2016) and compliant with only those parts of Clause 6 (Response to Area EPS abnormal conditions) of IEEE Std 1547-2018 (2nd ed.) that can be Certified per the type test requirements of UL 1741 SA (September 2016).
3. **Direct Transfer Trip**: The communication of a trip signal to a remote location.
4. **Generator**: Equipment that produces power.
5. **Generator Set:** The singular assembly of an electrical Generator and a Prime Mover, also known as a genset.
6. **Island:** A condition in which a portion of an area EPS is energized solely by one or more local DERs while it is electrically separated from the rest of the area EPS.
7. **Line Segment:** Any portion of the EPS circuit that can be isolated via a protective device, including but not limited to a sectionalizer, recloser, or circuit breaker.
8. **Non-certified DER:** Any inverter not Certified or any induction Generator or synchronous Generator.
9. **Point of Interconnection:** The point of interconnection references the location where GMP-owned interconnection facilities connect to the main distribution line that serves other customers.
10. **Prime Mover:** The mechanical equipment that drives the Generator to output power. For example, in a typical motor operated Generator, i.e., motor-Generator set, the motor would be considered the prime mover.
11. **Reclose Block:** Voltage supervised automatic reclosing of a protective device.
12. **Sandia Screen:** Refer to SANDIA Report SAND2012-1365.
13. **Supplemental DER:** Refer to IEEE1547-2018 section 3.0.

4.2 Acronyms

1. **DER:** Distributed Energy Resource. Refer to IEEE1547-2018 section 3.0.
2. **DTT:** Direct Transfer Trip.
3. **EPS:** Electric Power System.
4. **ESS:** Energy Storage System.
5. **GSU:** Generator Step Up transformer.
6. **ISO-NE:** Independent System Operator New England.
7. **ML:** Minimum Load for a specified interval.
8. **NRTL:** Nationally Recognized Testing Laboratory.
9. **PCC:** Point of Common Coupling. Refer to IEEE1547-2018 section 3.0.

10. **POI:** Point of Interconnection.
11. **PPA:** Proposed Plan Application.
12. **PQ:** Power Quality.
13. **RPA:** Reference Point of Applicability. Refer to IEEE1547-2018 section 3.1
14. **ROI:** Risk of Islanding.
15. **RTU:** Remote Terminal Unit.
16. **SCADA:** Supervisory Control and Data Acquisition.
17. **SFS:** Sandia Frequency Shift.
18. **SVS:** Sandia Voltage Shift.
19. **TGFOV:** Transmission Ground Fault Overvoltage.

5 Interconnecting Customer Interface Procedures

5.1 Application Process Overview

This section outlines the process for a Customer to receive Company approval to interconnect DER facilities to the Company's distribution EPS.

See https://greenmountainpower.com/help/net-metering-project-requirements-process/ for additional information.

5.1.1 Application Instructions

All interconnection applications are governed by VT PUC Rules 5.100 and 5.500. Links to these rules can be found at:

VT PUC Rule 5.100

VT PUC Rule 5.500

A. Applications for net metered facilities must adhere to VT PUC Rule 5.100 and shall submit applications to the VT PUC in accordance with the instructions outlined in VT PUC Rule 5.105, 5.106 or 5.107; as applicable.
   i. Customer registration or application submitted in accordance with VT PUC Rule 5.105 and 5.106 constitute both a CPG application to the VT PUC and an interconnection application to the Company.
   ii. Customers applying for a CPG in accordance with VT PUC Rule 5.107 must submit an interconnection application and associated materials to the Company.

B. VT PUC Rule 5.107 requires ground mounted facilities in excess of 150 kW AC to include as part of their CPG submission a letter from the interconnecting utility confirming that the proposed facility will not cause adverse impacts on system stability or reliability. In order for the Company to issue such a letter, the Customer must apply through the VT PUC Rule 5.500 process.

C. 30 V.S.A. § 8007(a) states that non-net metered projects less than or equal to 150 kW AC may utilize the net metering application procedure that would otherwise apply if they were net metered. Applications for non-net metered facilities greater than 150 kW AC must adhere to VT PUC Rule 5.500.

Interconnection applications to the Company should be emailed to dr@greenmountainpower.com.

Any application fee or study deposit should be mailed in the form of a check to:

Green Mountain Power
Distributed Resources
2152 Post Road
Rutland, VT 05701

For electronic payments, wire transfer information will be provided upon request.

5.1.2 Interconnected Customer Technical Data Submission

The Customer shall submit at the time of application all required documentation as specified in VT PUC Rules 5.100 and 5.500. The Company reserves the right to request additional information as needed specific to the interconnection of Customer equipment, including but not limited to site plans and documentation, electrical one line, equipment data sheet and operational details.

The Customer is required to notify the Company immediately if there is a change to proposed equipment or the technical information provided, including data sheets, one lines and site plans. It must be recognized that a change in any of this information could result in loss of interconnection queue position, negate study results and/or extend the time required, and associated study costs, for Company review.

5.1.2.1 Site Control

Customers applying for interconnection in accordance with VT PUC Rule 5.500 shall provide proof of site control pursuant to VT PUC Rule 5.504(B)(2).

5.1.2.2 One Line Diagrams

All submitted one-line diagrams shall depict the major Customer equipment and the anticipated Company equipment to be installed and/or associated with the proposed interconnection. For projects with a capacity greater than 150 kW AC, the one-line diagram shall be stamped by a Professional Engineer. The one line shall depict the following at a minimum:

A. Generator step-up (GSU) and auxiliary transformer(s) identifying transformer configuration and voltage
B. Generator DER and transformer(s) grounding method (i.e. floating, solid, impedance)
C. Point of Common Coupling (PCC)
D. Point of Interconnection (POI) with existing Company EPS
E. Company line extension to PCC from POI
F. Generator(s)/inverter(s); including location, quantity, size and type

5.1.2.3 Interconnection Facility Equipment Data Sheets

Customers applying for interconnection in accordance with VT PUC Rule 5.500, and others as determined necessary by the Company, shall submit all technical data associated with the specific distribution, protection and generation equipment included in the project. Submitted documentation shall highlight product numbers and information for the specific equipment/devices that will be installed as part of the project. Examples of required documentation specific to DERs include but are not limited to:

A. Documentation of adherence to applicable standards as shown in this interconnection guideline

B. Rotating machine impedance parameters for modeling
C. Inverter based system models and validation test data

The following documentation may be required during the interconnection study process:

A. Inverter Islanding detection information, including brief description of Islanding detection method, parameters monitored, parameters perturbed (for active Islanding methods), and whether positive feedback based methods are to be used
B. Documentation that inverters adhere to IEEE-2018 7.2.4 Transient Overvoltage Curve

5.1.2.4 Site Plan

Customers applying for interconnection in accordance with VT PUC Rule 5.500, and others as determined necessary by the Company, shall submit a site plan showing the location of major customer equipment, the Company equipment to be installed on site, and site details that will be helpful to define accessibility of the site. The site plan shall depict the following equipment at minimum:

A. GSU transformer(s)
B. Point of Common Coupling (PCC)
C. Point of Interconnection (POI) with existing Company EPS
D. Company line extension to PCC from POI
E. Generator(s)/inverter(s); including location, quantity, size and type
F. Company pole number nearest the proposed PCC
G. Existing service(s)
H. Existing relevant roadways

The Customer's site plan shall indicate proposed Company equipment or pole locations for coordination. Locations of Company equipment shall be noted as *"For informational purposes only. Final location to be determined by Company".* The Company shall determine the final location of Company equipment, typically during the design and construction phase.

5.1.2.5 Data Required for Energy Storage System (ESS) Applications

For applications proposing ESS, additional information will be required at the time of application for interconnection. Examples of such information include but are not limited to:

A. Method of ESS connection:
   i. ESS directly connected to Company EPS; or
   ii. ESS DC coupled with Generator; or
   iii. ESS AC coupled with Generator; or
   iv. ESS connected on load side of service point and utility revenue meter with the premises load

B. Provide the following operational characteristics (if unknown, Company will assume the worst-case scenario):

    i. Sequence of operation and time of day for the ESS' charging and discharging capabilities and the maximum ramp rate in Watts/second if known.

    ii. Identify markets the ESS intends to participate in.

5.2 Objectives in the Applications Process

1. For new electric service or modifications to an existing electric service connection to accommodate the Customer's DER system, refer to the latest revision of the Vermont Utilities Service Requirements Manual. The Customer will be responsible for any permitting and conformance to the latest revision of all local, state and federal codes and national standards that apply.

   The Customer will also be responsible for any additional costs associated with work completed by another entity (such as telephone company set poles). Project construction schedules can be significantly impacted by another entity's work.

2. Any subsequent sale of a DER facility whose interconnection is governed by an interconnection agreement with the Company shall require the new owner to update the notice and operational contact information contained within the existing agreement and follow, as applicable, the assignment provisions contained within the generation interconnection agreement.

3. The following ISO-NE requirements apply under this bulletin

    A. DER projects greater than 1 MW AC but less than 5 MW AC require a Generator notification by the Company to ISO-NE via Attachment 3, under ISO-NE Planning Procedure 5-1 (PP 5-1).

    B. DER projects greater than or equal to 5 MW AC require a review of transmission system impacts and a Proposed Plan Application (PPA) filed with ISO-NE. Refer to ISO-NE PP 5-1.

    C. For DER projects greater than 1 MW AC, ISO-NE may determine that a PPA is required which may result in additional study, consistent with ISO-NE Study and Performance Requirements in Planning Procedures 5-3 and 5-6. The project will be responsible for all associated costs.

4. The application process and attendant services are offered by the Company on a non-discriminatory basis to any Customer. As part of the process, the Company may identify the need for detailed engineering studies, EPS upgrades and additional protection requirements. If the Customer makes significant changes in the design or scheduling of their DER system, then any previous information furnished by the Company to the Customer is subject to review and possible change, which may cause a delay in service and/or additional cost.

5.3 Interconnection Charges

Customer is subject to charges for interconnection costs. These interconnection costs are directly related to the installation of those facilities the Company deems necessary for interconnection. Costs include, but are not limited to, initial engineering evaluations, interconnection studies, purchase and installation of additional switching, transmission, distribution, and communication equipment at Company's facilities, safety provisions, engineering and administration. These costs shall be paid in full by the Customer in accordance with VT PUC Rules 5.100 and 5.500.

6 General Design and Operating Requirement

There are three main types of DER that interconnect to the Company's distribution EPS. These include:

1. Induction Generators
2. Inverters
3. Synchronous Generators

For the purposes of this Interconnection Guideline, any reference to DER ratings refers to the nameplate rating of the generation. Equipment nameplates shall meet all applicable standards, including but not limited to ANSI and IEEE standards.

1. For inverters, this shall refer to the nameplate rating of the inverter(s). Derating of inverter based DER is not permitted[1].
2. For rotating machines, this shall refer to the nameplate rating of the electric Generator (as opposed to the nameplate rating of the Generator-set). De-rating of rotating machine Generators by their Prime Mover capabilities is not permitted.
3. For facility or campus-style microgrid connections, DER interconnection equipment, protective systems and microgrid controllers connected at the PCC to the Company's EPS are to be designed and operated according to this Interconnection Guideline and to any applicable industry codes and standards. The control scheme that will disconnect and reconnect the facility or campus-style microgrid from the Company's EPS must be reviewed and approved by the Company.

6.1 General Criteria

6.1.1 Delivery Voltage

The Company reserves the right to designate the type of service and delivery voltage based on the location of the Customer and the size and character of its proposed DER.

6.1.2 Single Phase

Single phase DER shall meet the following minimum characteristics: Nameplate rating of a single Generator or group of Generators equal to or less than 150 kVA AC. The Company reserves the right to require three phase interconnection on a case-by-case basis.

6.1.3 Three Phase

Other than permissible single phase connections, three phase connections are required.

[1] ESS is exempt from the derating limitation on inverter based DER.

6.1.4 Phase Balance and Voltage Tolerance

A. The Customer's DER shall generate equal current in each phase conductor at the PCC. Voltage unbalance resulting from unbalanced currents shall not exceed 3% and shall not cause objectionable effects upon or interfere with the operation of the Company's facilities and service to others. This criterion shall be met with and without generation.

B. The interconnection of the DER facility shall not affect the Company's ability to maintain voltages consistent with Standard ANSI C84.1.

6.1.5 Neutral Stabilization, Ground Faults, and Grounding

6.1.5.1 Multi-grounded distribution area EPS

A. The DER shall not significantly degrade the area EPS grounding system as determined by the Company. When evaluating whether a DER degrades EPS grounding, the Company may consider the following standards and factors. Note that this list is not exhaustive, and depending on individual circumstances, further evaluation may be required.

   i. IEEE C62.92 Series (IEEE Guide for the Application of Neutral Grounding in Electrical Utility Systems)

   ii. IEEE 1547 (All requirements addressing DER response to EPS voltages must be met. These include, but not limited to, the following:

      a. Reference points of applicability (4.2)
      b. Response to Area EPS Abnormal Conditions (Voltage – 6.4)
      c. Power Quality (7.4)

   iii. EPS ground relaying sensitivity

B. The Company notes that DER systems likely will not significantly degrade EPS grounding as determined by the Company under the following scenarios:

   i. For a typical inverter DER, the DER system, including the interfacing transformers:

      a. Is Certified to the latest standards. (Where testing certifications standards do not exist other testing documentation may be provided by mutual agreement between the customer and company.)
      b. Does <u>not</u> break the zero-sequence network (i.e. includes a grounded wye / grounded wye interfacing transformer)
      c. Does <u>not</u> substantially desensitize EPS protective relaying as determined by the Company.

   ii. For typical rotating machine DER, the DER system, including the interfacing transformers:

      a. Does <u>not</u> substantially desensitize EPS protective relaying as determined by the Company.
      b. Installs a Direct Transfer Trip (DTT) from upstream protective

devices.

iii. Other various configurations as determined through detailed study.

6.1.5.2 Non-effectively grounded area EPS

Due to the limited amount of non-effectively grounded distribution EPS in GMP's territory, the company will determine requirements at the time of study.

6.1.6 Power Factor

All DER shall meet the following power factor requirements:

i. 100% for inverter-based projects

ii. 98% (leading/lagging) for synchronous machines

iii. 95% (leading/lagging) for induction machines

6.1.7 Direct Transfer Trip

IEEE 1547 requires any DER on a distribution feeder to detect and be tripped offline within two (2) seconds upon formation of an Island from the area EPS. There are some cases where a DER's on-site equipment (such as voltage and frequency relaying or islanding detection) cannot reliably detect an Island. Where the Company determines that a significant risk of unintentional islanding exists, DTT may be required. DTT typically requires utility modifications to send a signal to trip the DER facility offline when an upstream gang-operated protective device operates. Acceptable communication mediums for DTT may utilize fiber optic cable, radio, or leased telephone lines. The communication medium to be utilized will be determined as part of a project's Facilities Study.

6.1.8 Transmission Ground Fault Detection

The addition of DER to a distribution feeder can result in reverse flow through the substation transformer. The Company's most common distribution substation transformer is configured delta on the transmission side and grounded wye on the distribution side. Due to the transformer's configuration,[2] it cannot contribute zero sequence ground fault current to single line to ground faults on a transmission line, and the voltage on the unfaulted phases may potentially rise to levels that exceed insulation ratings and cause damage to the substation and transmission line equipment. This situation can also leave transmission ground faults energized by the distribution-connected DER. If the Company determines there is a

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[2] There are other transformer configurations for which zero sequence continuity is broken and/or the DER is unable to reliably detect and trip offline for transmission ground faults. The Company determines when and which type of transmission ground fault detection is required based on the substation configuration on a case-by-case basis.

likelihood of a zero sequence overvoltage event, transmission ground fault detection equipment and substation modifications may be required[3].

6.1.9 Reclose Block

GMP's review process includes consideration of whether the proposed project, along with other DER on the affected portion of the EPS, is capable of supporting an unintentional Island. As part of its unintentional Islanding mitigation efforts, GMP may require a Reclose Block strategy to prevent the EPS from reclosing into an unintentional Island. Where required, Reclose Blocking employs a voltage supervised reclose permissive feature at the substation and mid-line protective devices capable of automatic reclosing. Where this feature is required, the protective device is also required to be SCADA equipped through the Company's preferred communication network.

6.2 Service Equipment and Revenue Metering

Refer to the following links and documents for service equipment and metering requirements:

1. https://greenmountainpower.com/help/net-metering-project-requirements-process/
    A. GMP Solar Service Requirements
    B. GMP Solar Meter Socket Connections
    C. GMP Socket Labeling
    D. Gross Solar Meter Battery Storage Install Form and Checklist
2. https://greenmountainpower.com/help/electric-service-requirements/
    A. Section 805, Customer Generation Operating in Parallel with the Utility System
    B. Section XI, Drawings 402 through 408

6.3 Transformer

6.3.1 DER Interconnecting to Secondary Voltage

The largest transformers for DER connections are 167 kVA single phase, 501 kVA three phase overhead, and 2,500 kVA three phase padmounted. The only three phase transformer configuration the Company will provide is a high voltage grounded wye and low voltage grounded wye transformer. Standard voltages are 120/240 single phase, 208Y/120 three phase, and 480Y/277 three phase.

[3] VT PUC Case No. 19-0441-TF resulted in an approved tariff of Green Mountain Power Corporation for a net-metering transmission ground fault overvoltage ("TGFOV") fee and new generation resource rider on bills rendered on or after July 1, 2019. GMP's tariff assesses a onetime fee of (currently at $37/kW AC, subject to change per Case No. 19-0441-TF) on all distributed generation (except ESS) interconnecting to a distribution network identified in the tariff proceeding as having an unmitigated TGFOV risk.

Non-standard transformers will not normally be provided by the Company and are not a typical stock item for the Company. The Company will determine when a dedicated service and transformer(s) are required in order to reduce the impact on other adjacent customers. If a dedicated transformer(s) is required, the Customer will be advised by the Company. The cost of the transformer(s) will be the responsibility of the Customer according to Rule 5.500.

DER facilities proposed on the Customer side of an existing Company-owned transformer may require the existing transformer service to be replaced.

6.3.2 DER Interconnecting to Primary Voltage

The Company reserves the right to specify the winding connections for the Customer supplied interconnection transformer between the Company's delivery point and the Customer's DER facility output terminals as well as whether it is to be grounded or ungrounded. The Customer shall provide their interconnection transformer's specifications and ratings for the Company's review and acceptance during its review or detailed study.

6.3.3 Effectively Grounded, Four-wire Multi-grounded Wye EPS

The preferred transformer configuration for DER is grounded wye – grounded wye. If the DER requests a different configuration, any additional requirements for safe and reliable interconnection will be the responsibility of the Customer and determined by the Company as part of any review or study.
Refer to section 6.1.5.1 of this Interconnection Guideline.

6.3.3.1 Not Effectively Grounded, Three-wire 3-phase EPS

Due to the limited amount of non-effectively grounded distribution EPS in GMP's territory, the company will determine requirements at the time of study.
Refer to section 6.1.5.2 of this Interconnection Guideline.

6.4 Manual Generator Disconnecting Means

The Customer's DER facility shall have an electrical load break disconnect switch accessible at all times to the Company to electrically isolate the Company's distribution EPS from the Customer's DER system. See the Vermont Electric Utilities Service Requirements Manual section 805F (refer to section 6.2). The Customer shall provide direct 24/7 unencumbered access to the disconnecting switch to allow Company personnel to operate the disconnecting switch and apply protective grounds as needed, without the need to contact the Customer. The Company will make efforts whenever possible to notify the Customer should the DER facility need to be disconnected; however, the Company reserves the right to operate the DER facility's disconnect without notice in emergency situations.

The Customer shall provide contact information for Customer personnel that can be reached 24/7, should complications arise with access to the Customer's equipment.

Should there be any complications with Company access to the DER disconnecting means, the Company reserves the right to disconnect the Customer's service in its entirety via the next upstream Company-owned disconnecting means.

The disconnecting means shall have the following characteristics (refer to the links in section 6.2 of this Interconnection Guideline):

1. Rating:

   Disconnecting means shall be rated to interrupt the maximum Generator output; meet applicable UL, ANSI, and IEEE standards; and shall be installed to meet the National Electrical Code (NEC) and all applicable local, state, and federal codes.

2. Arrangement:

   The disconnect switch shall be installed to have the line connection of the switch connected to the utility source. Secondary disconnects with more than one current carrying conductor shall be gang operated. Primary side disconnects shall be capable of being grounded on the Company side.

3. Type:

   A. The type of disconnecting means for all DER is subject to Company approval.

   B. For DER systems that are connected directly to the area EPS requiring a manual disconnecting means at the PCC that can be opened for isolation, the device shall normally be a blade-type switch with the ability to apply grounds or an alternate method determined to be acceptable by the Company. In accordance with the Company's safety rules and practices, this isolation device must be used to establish a visually open, working clearance boundary when performing maintenance and repair work.

   C. For DER systems connected to the Customer-owned distribution system requiring a manual disconnecting means downstream of the PCC, the disconnecting means may be a draw out circuit breaker, disconnect, or comparable device mutually agreed upon by the Company and the Customer. This device and all wiring must adhere to the latest revision of the NEC.

4. Location:

   In accordance with the Vermont Electric Utilities Service Requirements Manual section 805F and the latest revision of the NEC, a disconnecting or isolation means shall be required to be located between the Company meter and the DER device and must be accessible to allow for use by first responders and lockable in the open position.

   The location for the disconnecting means for all DER projects is subject to Company approval on a case-by-case basis and shall comply with Company standards for working clearances, access road construction, vegetation management, and other similar requirements to ensure adequate access for Company operating personnel and equipment.

5. Access and Locks:

   The disconnecting means must be readily accessible at all times to the Company to electrically isolate the Company's distribution EPS from the Customer's Generator facilities. In all instances, the disconnecting means shall have provisions to be locked in the open position with space for Company and Customer padlocks.

6. Identification:

All required disconnecting means shall be identified by a permanent sign as required by the NEC, the Vermont Utilities Electric Service Requirements Manual section 805 and the labeling document on the GMP website.

6.5 Generator Interrupting Device Requirements

For any DER, an interconnection interrupting device such as a circuit breaker, or other interrupting means, shall be installed at the Customer's site. This device shall be installed to meet the latest revision of the National Electrical Code (NEC) and all applicable local, state, and federal codes. During the review or detailed study the Company may require an additional interrupting device.

6.6 Protection and Protective Equipment Requirements

The Customer is solely responsible for the protection of their DER and premise equipment, including any customer equipment required by the Company to interconnect to the area EPS. All DER shall meet the requirements of the latest version of IEEE 1547 and all equipment (including Supplemental DER devices) are Certified by a Nationally Recognized Testing Laboratory (NRTL).

6.6.1 Site DER Protection Requirements

6.6.1.1 General

Area EPS protection owned and operated by the Company will not be used to satisfy the Customer DER's IEEE 1547 performance requirements.

6.6.1.2 Certified Inverter Based DER

Inverters shall be compliant with the latest version of IEEE 1547 and Certified per the latest testing standards.

The DER shall meet all of the performance requirements in IEEE 1547 at the Reference Point of Applicability (RPA). If the DER facility requires Supplemental DER device(s) to meet the performance requirements at the RPA, it shall be designed, supplied, and commissioned by the Customer and approved by the Company.

6.6.1.3 Non-certified DER

The DER shall meet all of the performance requirements in the IEEE 1547 standard at the RPA. The Supplemental DER device(s) that necessarily will be required to meet the performance requirements at the RPA shall be designed, supplied, and commissioned by the Customer and approved by the Company.

The Company will not allow a Non-certified DER utilizing an inverter that is not Certified.

6.6.2 Area EPS Protection Requirements

6.6.2.1 General

The Company may require additional protection in the Area EPS as part of the DER review or detailed study, including but not limited to line reclosers, fuses, and sectionalizers.

6.6.2.2 PCC Recloser Requirement

A. A PCC recloser is required for Certified inverter based DER greater than 500 kW AC.

B. A PCC recloser is required for Company approved Non-certified DER regardless of size.

C. A PCC Recloser may be required for Certified inverter based DER less than or equal to 500 kW AC.

6.6.3 Unintentional Islanding Screen and Protection Requirements

6.6.3.1 General

A. All DER shall detect an Island and must trip within 2 seconds of the formation of the Island.

B. Existing Certified inverter based DER with unintentional Islanding protection scheme to trip within 2 seconds will not be considered Non-certified DER for the unintentional Islanding screen.

C. Customer’s DER shall not energize any portion of the Company’s de-energized EPS.

D. The Company may close or reclose any Line Segment at any time without checking for de-energized DER.

E. DER equipped with DTT are not factored into the aggregate and ratio screens identified in the unintentional Islanding screen.

F. A distribution feeder may contain multiple Line Segments and may be analyzed separately as needed per the steps outlined in the unintentional Islanding screen.

G. See Appendix A and Appendix A.1 of this document for a visual flowchart of the unintentional Islanding screen and requirements as outlined below.

6.6.3.2 Unintentional Islanding Protection Requirements for Special Conditions

Company requires additional unintentional Islanding protection, including but not limited to DTT, in addition to the requirements from the unintentional Islanding screen below, and regardless of DER type, for the following special cases:

i. If line faults (phase and ground where applicable) cannot be cleared by DER protective device or the Company's PCC recloser.

ii. Unique arrangements not explicitly defined within this document at the Company's discretion.

iii. If the Company determines that an unintentional Islanding protection scheme is required in addition to the DER's own unintentional Islanding scheme as part of the DER review or detailed Risk of Islanding (ROI) study.

6.6.3.3 Unintentional Islanding Screen for Certified Inverter Based DER

A. All inverters shall have an 88% voltage trip within 2 seconds.

B. Proposed DER rated less than or equal to 150 kW AC.

   i. No additional requirements.

C. Aggregate Line Segment DER less than 1/3 of the minimum load (ML).

   i. No additional requirements.

D. Proposed DER is rated greater than 150 kW AC and less than 1000 kW AC.

   i. Line Segment aggregated Non-certified DER is less than or equal to 10% of the aggregate DER.

      a. No additional requirements.

   ii. Line Segment aggregated Non-certified DER is greater than 10% and less than or equal to 25% of aggregate DER.

      a. Sandia Screening[4] may be applicable depending on the proposed DER inverter model.
         1) The Sandia Screens are valid only for those Certified DER that have been confirmed, in writing from the manufacturer, to meet the definition of the Sandia Frequency Shift (SFS), or Sandia Voltage Shift (SVS) as positive feedback-based methods or for Certified DER using impedance detection with positive feedback.
         2) The Company will only review the DER using Sandia Screens #1, #2, and #3. When insufficient data exists to perform a complete reactive power balance review, Sandia Screen #2 shall be considered a failure.
         3) If the DER passed the Sandia Screen review, then no additional requirements.
      b. If Sandia Screen is not applicable or the DER failed the screen, a detailed ROI study may be performed if mutually agreed between the Customer and the Company.
         1) If results of the ROI study show no significant risk of Islanding for a period greater than 2 seconds, then no additional requirements.
      c. If a ROI study is not performed or the DER failed the study, a Company-owned PCC recloser and reclose blocking on Line Segment sectionalizing device are required.

   iii. Line Segment aggregated Non-certified DER is greater than 25% of aggregate DER.

[4] https://energy.sandia.gov/wp-content/gallery/uploads/SAND2012-1365-v2.pdf

a. A detailed ROI study may be performed if mutually agreed between the Customer and the Company.
    1) If results of the ROI study show no significant risk of unintentional Islanding greater than 2 seconds and the aggregate DER is less than or equal to 67% of ML or the DER is less than or equal to 500 kW AC, then no additional requirements.
    2) If results of the ROI study show no significant risk of unintentional Islanding greater than 2 seconds and the aggregate DER is greater 67% of ML and the DER is greater 500 kW AC, a Company-owned PCC recloser is required.
    3) If a ROI study is not performed or the DER failed the study, a Company-owned PCC recloser and a Reclose Block scheme on Line Segment sectionalizing device are required.

E. Proposed DER is greater than or equal to 1000 kW AC.

i. Company-owned PCC Recloser is required.

a. A Reclose Block scheme is required on any Line Segment sectionalizing device if the Line Segment aggregate DER is greater than 50% of ML.

6.6.3.4 Unintentional Islanding Screen for Non-certified DER

A. Required to meet the performance requirements of IEEE 1547 at the Reference Point of Applicability (RPA). See section 6.1.5 of this document.

B. If the aggregate Line Segment DER is greater than or equal to 33% of the ML, DTT is required.

6.6.4 Intentional Islanding Requirements

The Customer’s DER may not Island while connected on the Company EPS at any time. For intentional Islanding or microgrid connection requirements on Customer EPS, see section 6 of this document.

6.7 Monitoring and Control (M&C) at DER Facility

Certified DER facilities less than or equal to 150 kW AC may have monitoring required at the Company’s discretion. Certified DER facilities greater than 150 kW AC shall require monitoring communication to the Company’s supervisory control and data acquisition (SCADA) system. Certified DER facilities greater than 500 kW AC shall require monitoring and control to the Company’s SCADA system.

All non-certified DER shall require monitoring and control to the Company’s SCADA system.

Monitoring allows the Company’s system operators to have visibility and status of the DER’s output. This visibility is essential in maintaining system operability. Control allows the Company's system operators the functionality to remote trip the DER facility from the Company's EPS.

Monitoring shall be achieved by the installation of a Company owned SCADA remote terminal unit (RTU). Control shall be achieved by the installation of a Company owned PCC recloser. In the event that a PCC recloser is installed, monitoring can be achieved through this device.

Table 1: Monitoring and Control Requirements by DER Size *(Note 1)*

	DER less than or equal to 150 kW AC	**DER greater than 150 kW AC and less than or equal to 500 kW AC**	**DER greater than 500 kW AC**	**Non-certified DER**
Monitoring	Monitoring ***may*** be required	Monitoring ***shall*** be required	Monitoring ***shall*** be required	Monitoring ***shall*** be required
Control			PCC Recloser ***shall*** be required *(Note 2)*	PCC Recloser ***shall*** be required *(Note 2)*

Notes:

(1) RTU installations may be required for DER applications not covered by the conditions in this table as determined by the Company on a case-by-case basis.
(2) Where a SCADA connected PCC recloser is required, the need for a separate RTU is waived.

6.7.1 Company RTU input requirements

The minimum set of required data values at the PCC for DER greater than 150 kW AC and less than or equal to 500 kW AC range for basic monitoring shall include:

i. Per phase voltage and current
ii. Three phase values for real and reactive power
iii. Power factor

Additional monitoring to the RTU may be required from the DER and will be determined on a case-by-case basis by the Company. All monitoring information from the Customer DER to the Company RTU shall be provided over fiber using a DNP 3.0 protocol.

6.8 Voltage and Frequency Ride Through and Control Requirements

6.8.1 General requirements for all DERs

A. All DERs shall be in compliance with the latest revision of IEEE 1547. Field adjustable settings shall not be changed without written consent of the Company.
B. Default IEEE settings shall not be modified unless required by the Company.

C. Additional and/or modifications to the requirements within this section may be required by the Company as part of the interconnection process.

6.8.2 Certified DER requirements

A. Certified DERs shall meet the requirements of the latest version of the Inverter Source Requirement Document of ISO New England.[5]

B. In the overvoltage Permissive Operation region where the "Inverter Source Requirement Document of ISO New England" does not specify an operation mode, the Company requires the DER ride-through in the Momentary Cessation mode.

C. The maximum response times to overvoltage shall meet the requirements of the latest IEEE 1547 section 7.4 Limitation of overvoltage contribution.

6.8.3 Non-certified DER requirements

A. All Non-certified DER shall in good faith attempt to meet all of the Certified DER requirements. Refer to section 6.8.2 of this Interconnection Guideline.

B. Where Non-certified DER are not able to meet all the requirements of the Certified DER requirements (refer to section 6.8.2 of this Interconnection Guideline), the Customer shall propose alternatives (i.e. Supplemental DER) in accordance with latest version of IEEE 1547 to meet these requirements which will be subject to the approval of the Company.

C. The Company will not allow a Non-certified DER utilizing an inverter that is not Certified.

[5] https://www.iso-ne.com/static-assets/documents/2018/02/a2_implementation_of_revised_ieee_standard_1547_iso_source_document.pdf

7 Testing and Commissioning

1. The Company reserves the right to witness the Customer’s functional testing of the required devices, i.e., trip tests.
2. The Company reserves the right to witness-test/verify all Company-designated, Customer-owned relay functions and all synchronizing elements prior to energization.
3. The Customer is required to implement and functionally test the protection and control scheme with the Customer’s submitted design subject to all conditions required by the Company. The Company reserves the right to request written verification.
4. The Customer shall perform commissioning in accordance to VT PUC Rule 5.500.

8 Power Quality Monitoring

8.1 Power Quality Compliance Verification

If during the study a DER interconnection project is identified as having the potential to cause power quality (PQ) effects on the EPS, then PQ monitoring may be installed by the Company or Company-accepted third-party PQ testing company to verify the Customer is maintaining its power quality, with and without DER, in accordance with Company standards and all applicable requirements.

8.2 Power Quality Disturbance and Mitigation

1. If disturbances on the EPS and/or to other customers are suspected to originate from a Customer with DER, PQ monitoring shall be installed to verify the Customer is maintaining their power quality in accordance with the Company standards and all applicable requirements.
2. If it is determined that system modifications or changes are needed in order to mitigate the disturbance issue originating from the Customer DER, the cost of such modifications or changes shall be borne by the Customer.
3. If any power quality concerns, as a result of the Customer's DER installation, cannot be immediately corrected, the Customer **will not be permitted** to continue operation of the DER until such concerns are resolved.

8.3 Transient Overvoltage/Load Rejection Overvoltage (LROV)

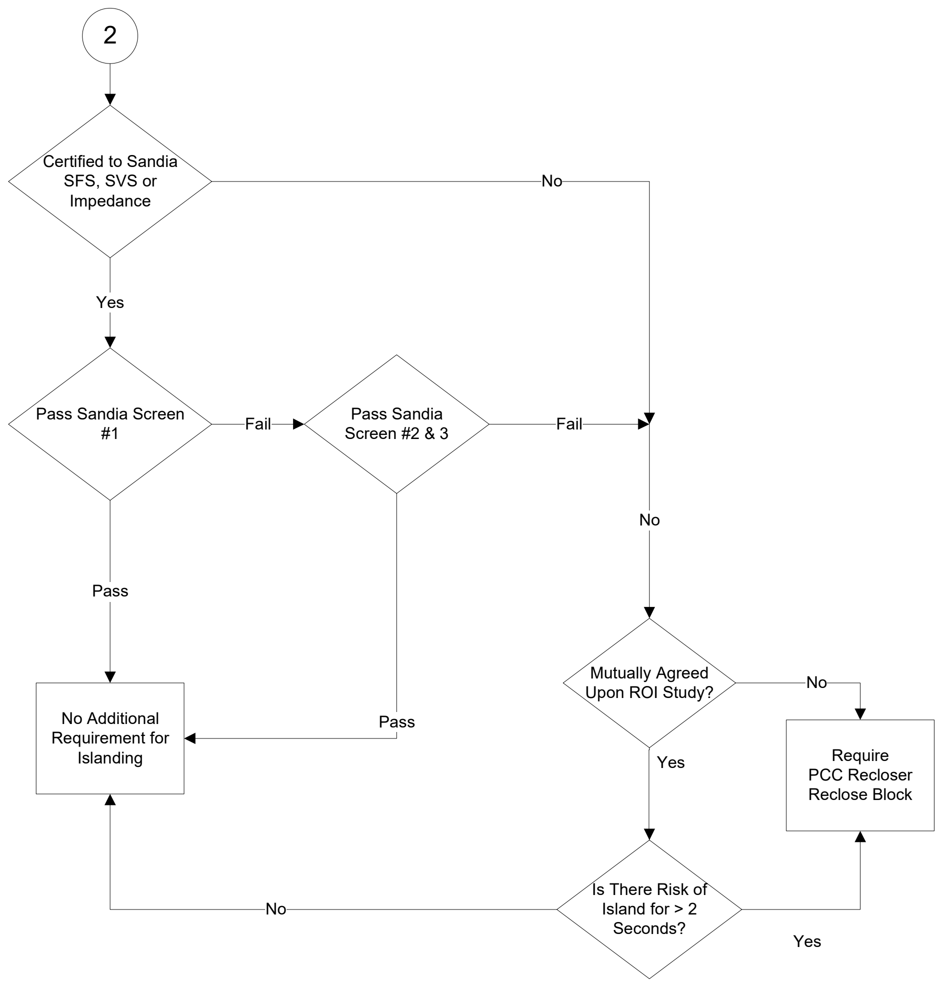
The DER shall limit its overvoltage contribution according to the latest version of IEEE Std. 1547 section 7.4 (Limitation of overvoltage contribution). The Customer shall provide a letter from the inverter manufacturer or a National Recognized Testing Laboratory (NRTL) confirming that the requirements from the standard are met. The letter shall be on the manufacturer or NRTL letterhead and include the firmware version and serial numbers of each inverter for the installation. Test data and/or standards certification supporting these statements may also be required at the discretion of the Company.

Compliance with these requirements relates to the DER's RPA (i.e. zero sequence continuity and transformer configuration). Refer to sections 6.1.5 and 6.3 of this Interconnection Guideline.

Failure to meet these requirements may require installation of a PCC recloser.

Appendix A: Unintentional Islanding Screen for Certified DER

Revision 3

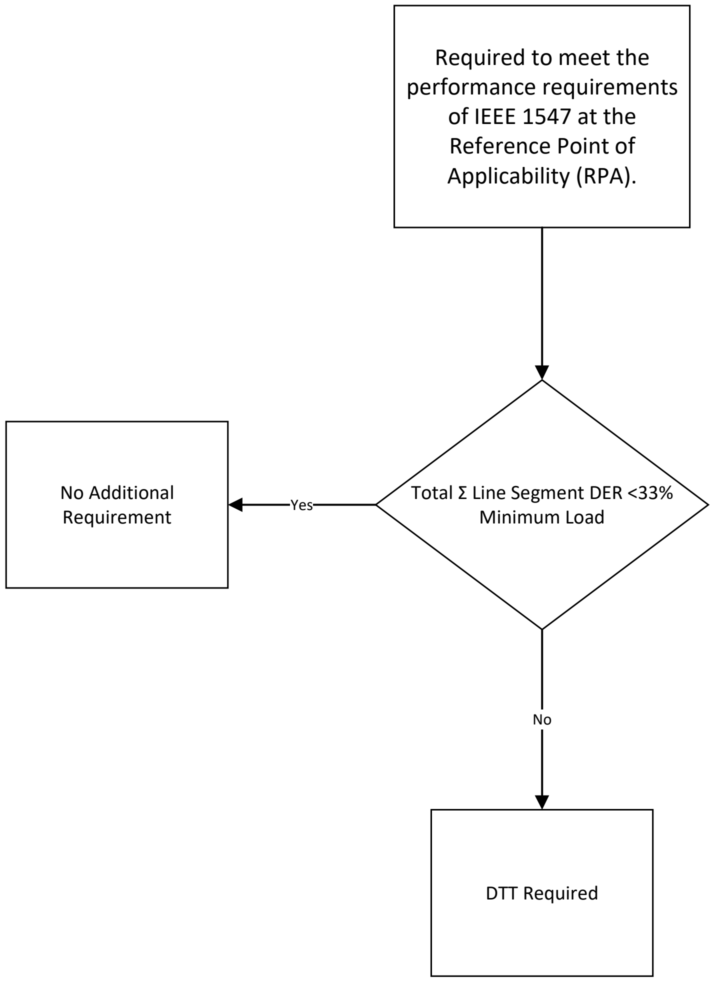


Note1: PCC Recloser may be required even if Unintentional Islanding Screening does not require a PCC Recloser, based upon other Company requirements.

Note 2: If the company determines that Unintentional Islanding protection scheme is required to mitigate the risk of a formation of an Unintentional Island in addition to the DER's own Unintentional Islanding detection scheme, then the company will require DTT.

Revision 3

Appendix A.1: Unintentional Islanding Screen for Non-certified DER



Revision 2

Revision History

Revision	Date	Author	Description
1.0	02/02/2021	GMP	Creation of this Document