

Massachusetts Technical Standards Review Group

Common Technical Standards Manual

To accompany M.D.P.U. No. 1320

Authors:

[Massachusetts Technical Standards Review Group](#)

Moody Demetry, Eversource

Michael Conway, Borrego Solar Systems

John Bonazoli, Unitil

Cynthia Janke, Eversource

Reid Sprite, SourceOne / Veolia North America

Michael Coddington, NREL

Michael Porcaro, National Grid

Jeannie (Piekarz) Amber, National Grid

Babak Enayati, National Grid

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2.0 Introduction

Massachusetts Electric Company and Narragansett Electric Company, each d/b/a National Grid (“National Grid”), NSTAR Electric Company and Western Massachusetts Electric Company, each d/b/a Eversource Energy (“Eversource”), and Fitchburg Gas and Electric Light Company d/b/a Unital (collectively referred to as the “Utilities”; individually referred to as “Utility”), with input through the Massachusetts Technical Standards Review Group (“TSRG”)¹, developed this Common Technical Standards Manual (“Manual”)² as a reference guide to identify areas of commonality and difference among the Utilities with regard to each of their technical standards and requirements for the interconnection of distributed generation (“Interconnection Requirements”) and to provide additional technical clarification of some Utility-specific Interconnection Requirements. This Manual is subject to each Utility’s uncontroverted ability to continue to apply a Utility-specific Interconnection Requirement that deviates from a common Interconnection Requirement followed by one or more of the other Utilities. Further, each Utility reserves the right to deviate from this Manual when, in its sole discretion, it determines it is necessary to do so. This Manual only addresses each Utility’s Interconnection Requirements applicable in The Commonwealth of Massachusetts.

The Manual is intended to serve as a reference tool only for a distributed energy resource (“DER”) interconnecting customer. The interconnecting customer must refer to the documentation referenced or provided by each Utility to determine the Utility’s specific interconnection standards and requirements, as well as each Utility’s interconnection tariff. Links to each Utility’s Interconnection Requirements are provided for convenience at Section 2.1 below and can be accessed on each Utility’s website. To the extent there is any conflict between this Manual and a Utility-specific Interconnection Requirement, the Utility specific Interconnection Requirement will take precedence over the Manual. This Manual is not all inclusive of the Interconnection Requirements and there may be Interconnection Requirements in addition to those addressed in this Manual applicable to any specific DER facility.

The Utilities have the absolute right to update and revise this Manual. Any revisions of this Manual will be provided to the TSRG and be made available on the Department of Energy Resources (“DOER”) website.³

This Manual refers only to each Utility’s Interconnection Requirements, and it shall be the interconnecting customer’s sole responsibility to ensure that the DER facility meets all applicable federal, state, and local, codes, rules, regulations, and laws.

¹ In its Final Report to the Department of Public Utilities (“Department”), the Massachusetts Distributed Generation Interconnection Working Group, as established in D.P.U. 11-75, recommended the creation of a Technical Standards Review Group (“TSRG”) to further address interconnection issues.

² This Manual was developed pursuant to the Massachusetts Distributed Generation Interconnection Working Group Final Report. *See Final Report, p. 30.*

³ Provided, however, neither notice to the TSRG or such posting is required prior to implementation of any Utility Interconnection Requirement.

3.0 Utility-Specific Standards and Guidelines

The following documentation should be referenced on a Utility-specific basis. The documents are Company standards or official guidelines pertaining to the parallel connection of distributed generation to the electric power system and the requirements therein take precedence over this document.

3.1 Eversource

Technical Specifications for Distributed Generation Interconnection

<https://www.eversource.com/content/ct-c/about/about-us/doing-business-with-us/builders-contractors/interconnections>

3.2 National Grid

ESB 756, Appendix C

http://www.nationalgridus.com/non_html/shared_constr_esb756.pdf

3.3 Unitil

Distributed Generation Interconnection Standards

<http://unitil.com/energy-for-residents/electric-information/distributed-energy-resources/generator-interconnection>

4.0 Anti-Islanding, Reclose Blocking, and Direct Transfer Trip

In the event that a portion of the utility electric system is electrically separated from the rest of the electric system, a Facility on that section of the system could possibly island with the load on that section, such that insufficient anti-islanding provisions at the Facility could lead to run-on times beyond the two-second limit prescribed in IEEE 1547. This could result in safety risks to line workers and the public, as well as equipment damage and reliability and power quality risks. Amongst all utilities, for cases where the line section aggregated DER is $\leq 33\%$ of minimum load, regardless of DER type mix, the risk of islanding (ROI) is considered negligible and no further screening is required. Each utility also reviews multiple line sections that the facility may be capable of islanding.

In this section Direct Transfer Trip is defined as protection scheme designed to automatically separate the Facility from the EPS via a remote (or loss of remote) signal from the utility by tripping one or more breakers at the PPC or within the Customer's Facility.

All risk of islanding studies, where applicable, are performed at the expense of the applicant.

4.1 Screening Process

For all Interconnection Applications, each Member Utility screens the Facility for potential islanding conditions.

Eversource:

ROI SCREENING PROCESS

All Proposed DER projects > 100 kW will be reviewed. The line section minimum load to aggregate DER ratio will be determined. This can be accomplished during a preliminary application review or as part of the system impact study. Pre-existing DER equipped with direct transfer trip (DTT) may not be factored into any aggregate DER screens identified within this document. DER at customer sites equipped with reverse power or minimum import relays should also be evaluated to determine the appropriate contribution to aggregate capacity screens.

If any line section has an aggregate DER-to-minimum load ratio >33%, the following evaluation is performed.

CERTIFIED DER

Line section aggregated non-certified DER is ≤ 10% of the mix and DER ≤ 2000 kW
No additional requirements related to ROI.

Line section aggregated non-certified DER is > 10% of aggregate DER or DER > 2000 kW.
Sandia screening (see Appendix C) shall be performed. Note - when insufficient data exists to perform a complete VAR balance review, Sandia screen #2 shall be considered a failure.

If Sandia screens are passed, no additional requirements related to ROI are enforced.

If Sandia screens are not passed, a dynamic risk of islanding study (D-ROI) may be offered. If the D-ROI study indicates negligible risk of islanding, no additional requirements related to ROI are enforced.

If the D-ROI study is either not offered, is declined by the applicant, or has unacceptable results, then an Eversource owned, SCADA-enabled recloser or other isolation device at the PCC is required. Reclose blocking of upstream devices will be evaluated. DTT may also be required (see Note 1).

NON-CERTIFIED INVERTERS, INDUCTION & SYNCHRONOUS MACHINES

A dynamic risk of islanding study (D-ROI) may be offered. If the D-ROI study indicates negligible risk of islanding, no additional requirements related to ROI are enforced.

If the D-ROI study is either not offered, is declined by the applicant, or has unacceptable results, then an Eversource owned, SCADA-enabled recloser or other isolation device at the PCC is required. Reclose blocking of upstream devices will be evaluated. DTT may also be required (see Note 1).

Note 1

In addition to a site recloser and the implementation of reclose blocking, Eversource reserves the right to require direct transfer trip (DTT) for projects with unique characteristics that create a high risk of islanding, either under existing or future circuit conditions. In those cases, Eversource will determine whether a detailed risk of islanding (ROI) study is warranted. If sufficient data is available to conduct a robust ROI study, and the results are reasonably expected to create information that may alleviate Eversource's concerns, the interconnection customer will be offered the opportunity to proceed with a detailed ROI study. If results of that study show no significant risk of islanding under all operating conditions for a period greater than 2 seconds, then Eversource will consider waiving the DTT requirement.

SPECIAL CONDITIONS

The following are conditions where additional EPS protection schemes, including but not limited to direct transfer tripping (DTT), may be required. These conditions may exist independent of the above ROI evaluation results.

- If line faults (phase and ground where applicable) cannot be cleared by DER protective device or Eversource owned PCC recloser.
- Unique arrangements not explicitly defined within this document at Eversource's discretion. This includes a consideration of off-normal circuit configurations.
- DER that cannot be tripped off with utility-owned devices when automated sectionalizing schemes operate.
- DER that cannot be tripped off within 2 seconds following the formation of an island, as this poses a risk to our customers and hinders operation of automated sectionalizing and restoration schemes.

National Grid:

National Grid generally does not require DTT for inverter-based UL1741 listed generators that do not regulate voltage, and instead requires reclose blocking where the aggregate generation on each line section does not pass the Sandia report screens. A Risk of Islanding study may be performed for inverter-based DER at the Customer's request. A complete distribution feeder may contain multiple line sections. Depending on the aggregate DER size to load ratio, multiple line sections may require review and be screened accordingly per the steps outlined. Each screen is repeated for each line section applicable to the proposed DER. Where DTT or reclose

blocking is required based on the screens, it shall be applied at the sectionalizing device for that line section. A utility owned recloser is required where aggregate line section DER \geq 300 kW and DER > 33% minimum load and is connected to < 5 kV EPS.

The Company may reclose at any distribution EPS segment at any time without checking for de-energized segments as normal system operations to maintain service reliability. It is important to the DER operator to be aware of this possibility as it is the responsibility of the DER operator to trip off within 2 seconds in the event the EPS utility source is not present.

Rotating machines and voltage regulating inverters require DTT if they meet or exceed 33% of the minimum load.

The screens are as follows:

Certified DER

1. All inverters shall have an 88% voltage trip within 2 seconds to be considered in this section.
2. Proposed DER rated \leq 50 kW
 - a. No requirements.
3. Proposed DER rated > 50 kW and < 1000 kW
 - a. Line section aggregated non-certified DER is \leq 10% of mix.
 - i. No additional requirements.
 - b. Line section aggregated non-certified DER is > 10% and \leq 25% of aggregate DER.
 - i. Sandia screening⁴ may be applicable depending on inverter models on segment.
 - ii. Company-owned PCC recloser and reclose blocking required if Sandia screens not passed.
 1. Detailed risk of islanding (ROI) study may be performed at the Customer-Generator's request. If results of the detailed study show no significant risk of islanding for a period greater than 2 seconds, then the recloser and reclose blocking is waived.
 - c. Line section aggregated non-certified DER is > 25% of all DER.
 - i. NG PCC recloser and reclose blocking required⁵
 1. Detailed ROI study may be performed at the Customer-Generator's request. If results of the detailed study show no significant risk of

⁴ The Sandia screens (<http://energy.sandia.gov/wp-content/gallery/uploads/SAND2012-1365-v2.pdf>) are valid only for those certified inverters 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 according to the report or for inverters using impedance detection with positive feedback. SFS and SVS both rely on positive feedback to work.

Positive feedback – detecting a deviation in grid parameters and acting to try to make that deviation from nominal worse. Where acting to try to make that deviation worse, the perturbations must push harder as the deviations from nominal increase. The algorithm must be able to push bi-directionally in order to be considered for this screen.

⁵ Where feasible, installing a PCC recloser in front of the non-certified DER may reduce or eliminate any further requirements to the subject applicant DER.

islanding for a period greater than 2 seconds, then reclose blocking is waived. Company-owned PCC recloser is waived for aggregate DER \leq 67% of line load to generation ratio or $<$ 500 kW.

4. Proposed DER rated DER \geq 1000 kW
 - a. Company-owned PCC Recloser required.
 - b. Reclose blocking required if line segment aggregate DER $>$ 50% of minimum load.

Non-certified & voltage regulating inverters, induction & synchronous machines

1. Require ANSI C37.90 utility-grade protective relay with IEEE 1547 voltage and frequency tripping and restoration functions.
2. Total aggregate line section DER $>$ 33% minimum load
 - a. DTT required.

Direct Transfer Trip may be required for the following:

1. Cases where additional EPS protection schemes, including but not limited to transfer tripping, may be required⁶
 - a. If line faults (phase and ground where applicable) cannot be cleared by DER protective device or the Company's PCC recloser.⁷
 - b. Unique arrangements not explicitly defined within this document at the Company's discretion.
 - c. If the DER cannot be tripped off with utility-owned devices when automated sectionalizing schemes will operate.
 - d. DER connected to $>$ 35 kV EPS where DER $>$ 50% onsite minimum load and the connecting line is radially supplied.

Unitil

During supplemental review and Impact Studies, DER applications that are larger than 100kW are screened for potential anti-islanding by load to generation ratio at each device location that could operate to form an island boundary (Line Section). Pre-existing DER equipped with direct transfer trip (DTT) may be removed from the aggregate generation for this screening process. For projects that fail the anti-islanding screening, Unitil requires a Direct Transfer Trip scheme be installed or offers to conduct a detailed Risk of Islanding study. The screening tools vary by type of DER technology, and are as follows:

If any line section has an aggregate DER-to-minimum load ratio $>$ 33%, the following evaluation is performed.

⁶ While the intent of this unintentional islanding protection policy is to encourage DER installations while minimizing inhibitive impacts to the DER installation, National Grid reserves the right and flexibility to enforce protective measures deemed required for the safety and reliability of the EPS.

⁷ Customers should be aware that $>$ 15kV class circuits typically involve more complex protection schemes, which can be more likely to require DTT due to inability to see and trip faults in an acceptable time frame, in addition to operational issues that may be present at these voltage classes (23kV and 34.5kV).

CERTIFIED DER

Line section aggregated non-certified DER is > 10% of aggregate DER or DER > 2000 kW.
Sandia screening shall be performed. Note - when insufficient data exists to perform a complete VAR balance review, Sandia screen #2 shall be considered a failure.

If Sandia screens are passed, no additional requirements related to ROI are enforced.

If Sandia screens are not passed, a DTT scheme is required or a dynamic risk of islanding study may be offered. If the dynamic risk of islanding study indicates negligible risk of islanding, no additional requirements related to ROI are enforced.

If the a dynamic risk of islanding study is either not offered, is declined by the applicant, or has unacceptable results, then a Company owned, SCADA-enabled recloser or other isolation device at the PCC and DTT is required .

NON-CERTIFIED INVERTERS, INDUCTION & SYNCHRONOUS MACHINES

A dynamic risk of islanding study may be offered. If the a dynamic risk of islanding study indicates negligible risk of islanding, no additional requirements related to ROI are enforced.

If the a dynamic risk of islanding study is either not offered, is declined by the applicant, or has unacceptable results, then an Unitil owned, SCADA-enabled recloser or other isolation device at the PCC is required. DTT may also be required

4.2 Reclose Blocking

The joint utilities may require reclose blocking (voltage supervised closing) where DERs are installed on the load side of an automated interrupting device. This may include substation interrupting devices and/or reclosers on distribution circuits.

National Grid Only: Reclose blocking may be required in lieu of DTT for certain UL1741 inverter-based systems per the screens in section 4.1.

4.3 Direct Transfer Trip

Direct transfer trip schemes may be required by the Joint Utilities to ensure safe and reliable operation of the Area EPS. The Joint Utilities require direct transfer trip as definitive means of anti-islanding detection. The scheme will be driven by a signal (or loss of signal) sent by the Member Utility and received and acted upon by equipment designated by the Member Utility to isolate the generator from the Area EPS. The communication medium required to install the transfer trip scheme may vary due to application. The installation and applicable monthly/maintenance cost of the communication medium is the responsibility of the Interconnecting Customer.

Other application cases may include, but are not limited to:

- N-1 system contingencies
- Off-schedule system configurations
- Any condition that may negatively affect system reliability or safety
- Mitigation of out-of-step reclosing
- Adverse system conditions that cannot be adequately detected and corrected with protective relaying schemes local to the DER facility
- Conditions where the DER is unable to see and trip for faults adequately.

5.0 DER Capacity – Feeder Limits

In general, the Joint Utilities have no defined limits on DER capacity on individual feeders. Capacity issues will be considered as part of the Impact Study or Supplemental Review. A study will identify limits based on thermal load flow, voltage rise, reverse flow through equipment, and voltage flicker.

Larger amounts of generation may be interconnected at the expense of the Interconnecting Customer by reconductoring or replacing equipment on a feeder as necessary to accommodate the increased thermal loading. Larger generation can be interconnected to express feeders if proper cable size is used and feeder breaker is available

5.1 Minimum Feeder Load

Measurement and data acquisition of the minimum load on individual feeders can vary from utility to utility and feeder to feeder. When measurement data is not available, the minimum feeder load is defined as 25% of the maximum peak load over the previous 12-month period.

6.0 Remote Monitoring and Control

Each utility requires remote monitoring and control means for facilities of a certain threshold size. This remote monitoring and control (RMAC) is typically in the form of a Remote Terminal Unit (RTU) or direct communication to a measurement device, which provides status of the monitored quantities at the site and control of an interrupting device (such as a circuit breaker or recloser). Where the joint utilities require a utility-owned PCC recloser, these requirements may be met with that device for IPP facilities. Some facilities consisting of both load and generation at the same site may be required to have a remote monitoring and control device (such as an RTU or similar equipment) in addition to the recloser so that both the load and generation can be monitored and controlled separately.

6.1 Remote Monitoring and Control Threshold Requirements

The Joint Utilities may require the installation of dedicated RMAC equipment. The necessity for RMAC is based on Facility size and voltage class of the Area EPS. If the size of the Facility exceeds the thresholds for each utility, RMAC equipment is required. Each utility reserves the right to require the monitoring listed below depending on the site size and conditions.

Eversource:

A recloser may be required for all sites $\geq 500\text{kW}$ sites.

National Grid:

National Grid reserves the right to require RMAC equipment for any facility 250kW and larger depending on the individual project conditions. For IPP systems, National Grid generally does not require an RTU, regardless of size or voltage class. Where required, National Grid will remotely monitor and control IPP-based generation using the National Grid-owned PCC recloser. For non-IPP customers, National Grid will require an RTU according to table 2, in addition to any utility-owned recloser requirement.

Table 1: RMAC (RTU) Requirement Thresholds for (non-IPP) Customers for National Grid

Area EPS Distribution Voltage Class	Facility Size
5 kV or below	≥ 500 kW
Greater than 5kV but less than 15 kV	$\geq 1,000$ kW
> 15 kV and <69kV	$\geq 1,800$ kW

Unitil:

Unitil requires an RMAC for all Facilities ≥ 500 kVA. Unitil also requires real-time remote monitoring for each individual unit of 500 kVA or more, even if the interrupting device at the PCC is also being monitored. For units from 60 kVA to 500 kVA, recording interval metering may be allowed instead of real-time monitoring and revenue metering can serve this purpose.

6.2 Data Acquisition and Control

The RMAC (recloser and/or RTU) must allow each Member Utility to monitor the Facility's status and to allow for remote disconnection of the Facility from the Area EPS as system conditions require.

Typical information required to be monitored may include and is not limited to the following data points:

- Net real power (kW)
- Net apparent power (kVA)

- Net reactive power (kVAR)
- Instantaneous phase current magnitude(Amps) – all phases
- Phase-to-phase voltages (Volts)– all phases
- Frequency (Hz)
- Facility breaker status
- Fault targets (if applicable)
- Status of main or interconnect breaker at the point of common coupling (PCC)
- Status of individual generator breakers
- Control input for the “designated generator interrupting device” for trip, block close & permit close functionality
- Protective relay status (if applicable)
- DC Control System Status (if applicable)
- Other status points, as required

6.3 RMAC Communications

Generally, the Customer is responsible for the installation and maintenance costs of the communications medium. In addition to any RMAC, the utility-owned PCC recloser (if available) will be controlled by each Member Utility through existing utility communications mediums.

National Grid: MPLS communication line leased from local communication service provider.

Eversource: MDS radio-based communication.

Unitil: Determined on a case-by-case basis.

6.4 Remote Operation

Where an RMAC or recloser is required, remote tripping of the site must be enabled. This control is installed to disconnect the generation from the Utility EPS.

7.0 PCC Protective Device Requirements

7.1 Reclosers

The Joint Utilities require a utility-owned PCC recloser to be installed for all large Facilities. In general, the recloser requirement will be governed by the Facility sizes and voltage classes listed in Table 2. The Joint Utilities reserve the right to implement a recloser in any case it is deemed necessary to interconnect a Facility with the potential to cause an adverse condition.

Table 2: PCC Recloser Requirement Thresholds

Area EPS Voltage Class	Facility Size	Recloser Required?		
		Eversource	National Grid	Unitil
≤ 5 kV	≥ 500 kW	Yes	Yes	Yes
≥ 15 kV	≥ 1,000 kW	Yes	Yes	Yes

If it is determined that islanding is of concern per section 4.1, a recloser may be required by the Joint Utilities.

7.2 External Disconnects

External disconnects are required by the Joint Utilities. Each Member Utility has a different threshold for when an external disconnect is required, as detailed in Table 3. The switch shall at minimum provide a visible break, be lockable in the open position and be accessible by the utility 24/7 at all times of the year.

Table 3: External Disconnect Requirement Thresholds

Member Utility	Facility Size
Eversource	All sizes
National Grid	≥ 25 kW ⁸
Unitil	> 10 kW

8.0 Witness Test Protocols

Witness testing is required for all facilities, but may be waived for simplified and some expedited projects using UL1741 certified inverters at the discretion of the utility. Witness tests are required for all sites that require a utility-grade protective relay.

⁸ If the unit is UL 1741 Listed inverter-based and has a disconnecting means integrated into the design and meets the requirements of the National Electrical Code (NEC), an additional external disconnect may not be required below 25kW.

8.1 General Requirements

During a Witness Test, each Member Utility inspects the completed Facility for compliance with the interconnection requirements. The Customer will provide a proposed Witness Test procedure and all requisite supporting documentation for review by the Member Utility once the Customer has completed the installation of the Facility.

Utilities generally require utility grade relay redundancy for sites 500kW or greater. Smaller facilities that are not using certified generators also require a witness test for the utility grade relays. Where UL1741 certified generation is accepted for utility grade relaying, testing of generator internal relaying, as well as certification by a nationally recognized testing laboratory that employs UL 1741 testing standards is required. A witness test may be required on a case-by-case basis for all facilities, including storage.

The witness test must be conducted by a third party, and attended by a Member Utility representative for supervision and approval of results.

8.2 Witness Test Procedures

Each witness test shall include both a calibration check and an actual trip of the circuit breaker or contactor from the device being tested. Visually setting a calibration dial, index, or tap is not considered an adequate calibration. Testing typically includes, but is not limited to:

- CT and CT circuit, polarity, ratio, insulation, excitation, continuity, and burden tests (excitation test results may be submitted prior to the witness test for most facilities).
- VT and VT circuit, polarity, ratio, insulation and continuity tests (results may be submitted prior to the witness test for most facilities).
- Relay pick-up and time delay tests (In some cases a certified testing letter may be acceptable, provided the test results include polarity and ratios for instrumentation devices).
- Functional breaker trip tests from protective relays
- Relay in-service test to check for proper phase rotation and magnitudes of applied currents and voltages
- Breaker closing interlocks tests
- Paralleling and disconnection operation
- Anti-islanding function (if applicable)
- Non-export function (if applicable)
- Synchronizing controls (if applicable)

- Proof of inability to energize de-energized lines and 5-minute reconnect time
- Proof of fail-safe relay design (where all relay functions may not be fully redundant)

8.3 Documentation

It is the Customer's responsibility to prepare all witness testing documents and procedures with sufficient time for review by the utility prior to scheduling the witness test. At a minimum, the following documentation is required:

- Witness test procedure
- Energization plan
- Current PE-stamped single-line diagram
- Relay settings
- Relay bench test results (if applicable)
- Current and Voltage Transformer Test Reports.
- Letter of Completed On-site Testing from Test Company
- Transformer test report (if applicable)

8.4 Testing Points

Relay set-points should be specified in accordance with utility requirements and IEEE 1547. Under-frequency ride-through should be modified according to the NPCC A.03 curve.⁹ Clearing times include breaker operation. At a minimum, the following relay functions shall be tested during the witness test:

- 27 Under-voltage
- 59 Overvoltage
- 81O Over-frequency
- 81U Under-frequency
- 51N Neutral Overcurrent (where applicable)
- 51 Phase Overcurrent (where applicable)
- 51C Phase Overcurrent (voltage-controlled, where applicable)
- 59N Neutral Overvoltage (where applicable)
- Breaker Failure (where applicable)

The Joint Utilities may require additional protections not listed here depending on the site configuration.

⁹ New England ISO may update ride through and tripping requirements for DERs.

8.5 Failure Protocol

In the event that a Facility fails a witness test (i.e. test results of a relay function fall outside of a certain tolerance), the witness test will be rescheduled, and the failed elements will be retested.

9.0 Power Factor

All Facilities are required to maintain a pre-determined static power factor. Typically each utility requires unity power factor operation at the generator device terminals, but may require off-unity depending on site conditions. Equipment may be required to be installed at the Facility if the generator source is unable to meet the specified power factor. Active voltage regulation may be permitted on a case-by-case basis.¹⁰

10.0 GSU Transformer Winding Configurations

With few exceptions, the Joint Utilities maintain multi-grounded systems, and the Customer's generation step-up (GSU) transformer winding configuration must be compatible with the Area EPS. In all service territories, neutral grounding reactors or resistors (NGR) may be required in the event that utility grounding fault detection is compromised by the addition of the Facility. Each Member Utility maintains a handful of ungrounded circuits, for which alternate winding configurations may be acceptable. However, for standard, four-wire, multi-grounded circuits, the acceptable transformer configurations are shown in Table 4.

Table 4: Permitted Transformer Winding Configurations for Multi-Grounded Circuits

Primary (Utility)	Secondary (Customer)	Added Requirements
Wye-grounded	Delta	NGR (if necessary)
Wye-grounded	Wye-grounded ¹¹	Effectively grounded DER source
Wye-grounded	Wye-grounded ¹¹	Secondary grounding transformer

National Grid only may also permit a delta primary transformer or ungrounded connection if a primary-side grounding transformer is added.

¹⁰ Active voltage regulation may require direct transfer trip per section 4.1.

¹¹ Assumes high magnetizing impedance for 3-legged core-type transformers.

11.0 Utility Grade and Redundant Relaying

For all Facilities with a capacity of 500 kW or greater, the Joint Utilities require redundant utility-grade relaying to disconnect the Facility under faulted conditions. In addition, redundant relaying may be required for Facilities with a capacity of 250 kW or greater depending on site conditions. Utility-grade relaying is required for all synchronous and/or non-UL1741 certified generators. The Joint Utilities reserve the right to require redundant relaying for any installation in order to maintain safety and reliability.

The location of the relaying is determined by the location of the generator grounding source (e.g. based on the transformer winding configuration, generator grounding, or location of grounding banks). Upon approval, protection functions provided by a Member Utility-owned recloser at the PCC may be considered as providing redundant relay functionality. Customer-owned relays must be located on the utility side of the grounding source, if applicable, on the customer side of the PCC. For a list of required relays, refer to the Witness Test Section 8.0.

12.0 Substation Reverse Power Flow

The Joint Utilities permit reverse power flow through the substation supply transformers, although System Modifications may be required to do so. Any proposed Facility that has the potential to cause reverse power flow through a substation transformer will require a System Impact Study (SIS). The SIS will specifically address the ability of the transformer to accommodate reverse power flow. During the SIS, the following items will be evaluated.

12.1 System Voltage Control

System voltage control includes load tap changers or voltage regulators. The SIS determines if system voltage control can be maintained at various boundary conditions, and will evaluate excessive controller operation caused by intermittent DER sources. The SIS will also evaluate the capability of the controller to accommodate reverse power conditions and to respond with appropriate control strategies.

Voltage and current inputs must be available to the system voltage controller. Any controller configuration that is not appropriate for reverse power must be replaced with a suitable controller with both voltage and current inputs. The requirement to add a backup controller will also be evaluated. Controller upgrades may be required system modifications resulting from DER facility interconnection.

Controller settings will be determined on case-by-case analysis of DER type and penetration.

12.2 Capacity Limit

Intermittent reverse power flow will be permitted up to a level consistent with each Member Utility's standards for transformer loading. The reverse power flow limit is based strictly on the transformer nameplate, with no consideration given to any forward power load on the transformer. Reverse power flow that will significantly add to the transformer insulation loss of life on a routine basis, based on the transformer specification and the insulation aging description in the latest version of IEEE Std. C57.91, will be evaluated. Any required transformer upgrades will be included in system modifications required to interconnect the DER Facility.

DER Facilities must supply a balanced three-phase output such that there would never be a situation where a substation transformer could experience forward power flow on one or more phases while experiencing reverse power flow on the other phase(s).

12.3 Transmission Ground Fault Protection

For situations where the total DER on the substation is approaching the minimum load of the substation, reverse power flow and the likelihood of the DER being able to sustain overvoltage conditions in the event of a single line to ground fault on the high side of the substation transformer are of concern. In these instances, zero-sequence overvoltage relaying (59N) is required on the high-side of the supply transformer (if delta or otherwise ungrounded) to detect and trip the DER's contribution to transmission ground faults. In instances where primary instrumentation transformers are not viable, DTT may be used to disconnect the facility for transmission faults.

13.0 Simplified Spot and Area Network Interconnections

For all UL 1741 Listed Inverter-based Facilities connecting to a Spot or Area Network that have a total nameplate rating less than 1/15 of the Customer's minimum load and 15kW or less qualify for the Simplified interconnection track per the interconnection tariff. Facilities that do not qualify for Simplified interconnections require a study per the Standard process.

14.0 Voltage Flicker

During the Expedited Review process, voltage deviations of greater than 2.0% will prompt the application to be moved to a full System Impact Study.

15.0 Detailed Study

The Detailed Study from each utility follows the requirements of the tariff. Each utility provides an Estimated Project Construction Schedule/Duration which will include a description of major milestone items, duration of each milestone item in weeks, and responsible party for that item.

In general, unless otherwise noted on the schedule, milestone items are assumed to be sequential, in that one must be completed before the next may proceed. Delays at any one milestone item, including but not limited to, weather, force majeure, customer response, transmission outage requirements, or other unforeseen circumstances outside of utility control will result in delay of total project time line. The information included is on a case-by-case basis for the project as determined by the results of the detailed study and are subject to each utility's construction terms and conditions.