Massachusetts Technical Standards Review Group

Common Technical Standards Manual

To accompany M.D.P.U. No. 11-75-E

Authors:
Massachusetts Technical Standards Review Group
Chair: Babak Enayati, National Grid
Vice Chair: Michael Conway, Borrego Solar Systems
Michael Brigandi, Eversource
John Bonazoli, Unitil
Cynthia Janke, Eversource
Reid Sprite, SourceOne Energy Solutions
Michael Coddington, NREL
Michael Porcaro National Grid
Jeannie Piekarz National Grid

1.0 Introduction

This document has been developed to highlight commonalities and differences among Massachusetts public electric utilities with regard to technical standards, practices, and requirements for the interconnection of distributed generation. This document was developed by the Massachusetts Technical Standards Review Group, a joint venture between National Grid, Eversource, and Unitil, with input from appointed representatives from stakeholder DG industries and Government departments. It was developed at the request of the Massachusetts Distributed Generation Working Group, under order of the Massachusetts Department of Public Utilities. This document serves to augment the Standards for Interconnecting Distributed Generation (the Tariff), and provide additional technical clarification of Company-specific policies throughout the state of Massachusetts. The Common Technical Standards Manual serves as a base-level guideline for the interconnecting customer, and any Utility-specific technical standard may take precedence over the guidelines outlined within. Future revisions of this document will be made available on the DOER TSRG Homepage.

2.0 Existing Utility-Specific Standards and Guidelines

The following documentation should be reference 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.

2.1 National Grid – ESB 756, Appendix C

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

2.2 Eversource East– Technical Specifications for Distributed Generation Interconnection

https://www.eversource.com/Content/docs/default-source/ema---pdfs/ma-dg-standards.pdf?sfvrsn=0

2.3 Eversource West – Technical Specifications for Distributed Generation Interconnection

https://www.eversource.com/Content/docs/default-source/ema---pdfs/ma-dg-standards.pdf?sfvrsn=0

Unitil – DG Interconnection Standards

Link to Unitil company specific standards

3.0 Anti-Islanding

In the event that a portion of the utility electric system is electrically separated from the rest of the electric system, a DG facility on that section of the system could possibly island with the load on that section, such that insufficient anti-islanding provisions at the DG facility could lead to run-on times beyond the 2 second limit prescribed in IEEE 1547. The following section describes each utilities' anti-islanding screening methodology, as well as mitigation requirements for projects that fail anti-islanding screening.

3.1 National Grid

3.1.1 Screening

DG applications under the Standard process, as defined by MDPU 1248, are screened for potential islanding conditions. National Grid requires DTT for all projects that fail anti-islanding screening, and when appropriate offers the option for the customer to undergo a detailed Risk of Islanding analysis to determine if DTT can be avoided. The screening tools vary by type of DG technology, and are as follows:

- Feeders consisting of inverter based PV only:
  - If total distributed generation on the feeder is greater than or equal to 67% of the minimum load from the previous 12 months, then the Sandia 2012-1365 screening tool is applied*. The Sandia tool is only considered applicable for inverters meeting the anti-islanding algorithm requirements described within Sandia report. If the screens are not passed, DTT is required. The option to undergo a detailed Risk of Islanding study is available if so desired by the customer.

    *Note that National Grid has added some margin to the mix of inverters screen within the Sandia screening tool, which evaluates the ratio of a particular inverter make/model relative to the total quantity of inverters. For this screen National Grid uses 75% instead of 67%, which is suggested by Sandia. This is due to lack of public studies being available to show that 67% provides margin. (i.e. there may be a potential islanding risk at 67%)

    - For those inverters not compliant with the Sandia criteria, the Sandia screens cannot be applied. As a result DTT is required. The option to undergo a detailed Risk of Islanding study is available if so desired by the customer.
- Feeders consisting of rotating generation only:
    - If aggregate rotating generator size is less than 33% minimum feeder load then DTT is not required.
    - If aggregate rotating generator size is greater than or equal to 33% minimum load and there are enough VAR sources on the islanded section of the feeder to self-excite the generator, DTT is required. Due to the nature of generation from rotating machines, the option to undergo a detailed Risk of Islanding study is not available to the Customer.
- PV in parallel with rotating generators:
    - If inverters are compliant with the Sandia criteria, the Sandia 2012-1365 screening tool is applied. If total distributed generation on the feeder is greater than or equal to 67% of the minimum load from the previous 12 months, then islanding is a concern and the following evaluations are performed:
        - If aggregate rotating generator size greater than or equal to 25% aggregate total DG rating and there are enough VAR sources on the islanded section of the feeder to self-excite the

generator, DTT is required. Due to the nature of generation from rotating machines, the option to undergo a detailed Risk of Islanding study is not available to the Customer.

- If aggregate rotating generator size is less than 25%, the inverters are examined:
    - If the inverters not compliant with the Sandia criteria, the Sandia screens cannot be applied. As a result DTT is required. The option to undergo a detailed Risk of Islanding study is available if so desired by the customer.

If a detailed Risk of islanding study determines that run-on times can exceed 2 seconds, a direct transfer trip scheme is required.

3.2 Eversource East

3.2.1 Screening

Screening tools pertaining specifically to Islanding include those highlighted in the SANDI Report 'Suggested Guidelines for Anti-Islanding Screening'. These Criteria are used to determine whether there is a risk of failure of the local islanding detection at a given facility that may cause an Island. If a risk is identified, Eversource East may implement a more advanced protection or transfer trip scheme, ask for system upgrades or suggest the customer decrease the power their facility is exporting.

Unitil

3.2.2 Screening

During supplemental review and Impact Studies, DG applications are screened for potential anti-islanding by load to generation ratio at each device location that could operate to form an island boundary. Unitil conducts detailed Risk of Islanding studies for all projects that fail anti-islanding screening. The screening tools vary by type of DG technology, and are as follows:

- PV: Sandia 2012-1365 screening tool
- Rotating Generation: If aggregate rotating generator size <33% minimum feeder load then anti-islanding study is not required. If aggregate rotating generator size >33% minimum load and there are enough VAR sources on the islanded section of the feeder to self excite the generator, islanding study is required.
- PV in parallel with rotating generators: If aggregate rotating generator size > 20% aggregate PV rating and there are enough VAR sources on the islanded section of the feeder to self excite the generator, islanding study is required.

If a detailed Risk of islanding determines that run-on times can exceed 2 seconds, a direct transfer trip scheme is required.

3.3 Eversource West

3.3.1 Screening

Preliminary screening tools such as load to generation ratio and amount and type of existing and proposed generation on the feeder are used to determine whether there is a risk of islanding. A 2:1 ratio of minimum daytime load to aggregate maximum generation is used when only Listed inverter based PV generation exisits in a line section. A 3:1 ratio of minimum load to aggregate maximum generation is used for a mix of generation types in a line section. DTT is required is the ratios are not met per feeder section.

3.4 Anti-Islanding Mitigation (Common)

Direct Transfer Trip is the common means of anti-islanding mitigation. Leased phone-line is the most common communications medium, although radio systems can be used where line-of-sight is available.

4.0 Other DTT Utilizations

4.1 National Grid

A Transfer Trip scheme may be required by the Company in order to ensure safe and reliable operation of our Distribution/Transmission System. A Transfer Trip scheme is a system that automatically isolates the Customer’s generator during a potentially adverse condition where control and protection solutions located solely at the DG facility may not be able to detect the condition. If a transfer trip scheme is deemed necessary, Company engineering will explain the necessity and cost for implementing that solution with the customer. The scheme will be driven by a signal sent by the Company and received and acted upon by equipment designated by the Company to isolate the generator from the Company EPS. The communication medium required to install the transfer trip scheme may vary due to application and may include radio, phone, power line carrier, or high speed fiber.

Application cases may include but are not limited to mitigation of: Islanding concerns, negative system impacts , N-1 system contingencies, off schedule system configurations, any condition that may negatively affect system reliability or safety of the public or our work force, or mitigation of out of step reclosing.

4.2 Eversource MA

A Transfer Trip scheme may be required by the Company in order to ensure safe and reliable operation of our Distribution/Transmission System. A Transfer Trip scheme is a system that automatically isolates the Customer's generator during a potentially adverse condition where control and protection solutions located solely at the DG facility may not be able to detect the condition. If a transfer trip scheme is deemed necessary, Company engineering will explain the necessity and cost for implementing that solution with the customer. The scheme will be driven by a signal sent by the Company and received and acted upon by equipment designated by the Company to isolate the generator from the Company EPS. The communication medium required to install the transfer trip scheme may vary due to application and may include radio, phone, power line carrier, or high speed fiber.

Application cases may include but are not limited mitigation of: Islanding concerns, negative system impacts , N-1 system contingencies, off schedule system configuration any condition that may negatively affect system reliability or safety of the public or our work force, mitigation of out of step reclosing.

4.3 Unitil

Direct transfer trip schemes are used as an anti-islanding mitigation practice and may also be required for other adverse system conditions that can not be adequately detected and corrected with protective relaying schemes local to the DG facility.

5.0 DG Capacity – Feeder Limits

5.1 National Grid

80% of the feeder cable thermal rating (aggregate 9 MVA generation on a 15kV class feeder) is the limit for the regular feeders. Larger amounts of generation may be interconnected at the expense of the customer to reconductor the feeder as necessary to accommodate the increased thermal loading. Larger generation can be interconnected to the express feeders if proper cable size is used.

5.1.1 Minimum Daytime Load Approximation if the measurement data is not available

Minimum load = 25% of maximum Peak as taken from the previous 12 month period.

5.2 Eversource MA

No hard limits by voltage level. Capacity issues are 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, voltage flicker and system modifications developed to mitigate the concerns. A stiffness factor test and penetration tests are also used to determine feeder capacity. Minimum load periods are typically determined from multiple data sources, or estimated from loadflows. Minimum load can vary by circuit based on nature of circuit and type of customers.

Unitil

Capacity issues are considered as part of the System Impact Study. No hard limit.

5.2.1 Minimum Daytime Load Approximation if the measurement data is not available

Minimum load = 25% of Peak

6.0 Remote Control & Monitoring

6.1 National Grid

National Grid requires the installation of an RTU for non-Independent Power Producer DG applications at the following thresholds:

5kV: DG $\geq$ 500kW

15kV: DG $\geq$ 1MW

+15kV: DG $\geq$ 1.8MW

The RTU is intended for the company's use in monitoring and remote control of the customer DG interconnection. Communication is achieved via a customer owned leased line from the local telecommunications vendor. Remote control is installed to operate the generator breaker, parallel to the load. At the request of the customer, it is permissible to control the main breaker of their site, in series with the load. Either approach is acceptable, provided that the ultimate goal of disconnecting the DG from the company power system is achieved. In addition to the RTU, the PCC recloser will be controlled through telemetrics. Any device capable of DNP3 can be used in lieu of the RTU.

For Independent Power Producer (IPP) applications, pole-top reclosed are utilized for analog and status points at the Point of Interconnection.

6.1.1 Data Monitored

- kW, kVA, KVAr
- A,B,C phase amps
- A-B, B-C, C-A voltages
- Customer breaker status (supervisory only)

6.1.2 Communications Medium

- Customer owned multi-protocol line (MPLS) leased from the local telecommunications vendor.

6.2 Eversource MA

PCC Reclosers bring back the following data to SCADA:

- Position indication
- Fault Targets
- Power Metering Quantities

6.2.1 Data Monitored

- Net Power

6.2.2 Communications Medium

- MDS Radio

6.3 Unitil

Unitil requires the installation of real-time remote monitoring and control via a RTU or similar equipment for DG facilities of 500 kVA and above. This monitoring is required at the designated interconnection Interrupting Device for the overall DG facility. If a company-owned recloser at the PCC is being required for other reasons, monitoring of that recloser can serve this purpose.

In addition, Unitil also requires real-time remote monitoring at any Interrupting Device for each individual unit of 500kVA or more, even if the Interrupting Device for the overall DG facility is also being monitored. For units from 60kVA to 500kVA, recording interval metering may be allowed instead of real-time monitoring, and revenue metering that may otherwise already be required can serve this purpose.

6.3.1 Data Monitored

- Connection or Unit Status
- Active and Reactive Power Flow (three-phase)
- Voltage – facility or unit side (per phase)
- Voltage – utility side

- Current (per phase)
- Frequency – facility or unit side
- Protective Relay Status (if applicable)
- DC Control System Status (if applicable)
- other states or quantities as specifically warranted

6.3.2 Communications Medium

- to be determined case-by-case

7.0 PCC Recloser Requirements – Threshold DG Size

7.1 National Grid

For independent power producers and non-independent power producers:

- 5kV: Interconnections greater than or equal to 500kW
    - For sites between 250kW and 500kW, it is the discretion of the company given the unique circumstances of the interconnection as to whether or not a recloser is required.
- 15kV: Interconnections greater than or equal to 1000kW
    - For sites between 500kW and 1000kW, it is the discretion of the company given the unique circumstances of the interconnection as to whether or not a recloser is required.

7.2 Eversource MA

Eversource may install a recloser at any DG PCC with an aggregate nameplate of 500kW or greater. However Eversource reserves the right to install a recloser for generation facilities when we determine it is necessary.

7.3 Unitil

DG ≥ 1MW

NOTE: Utilities reserve the right to implement a recloser in any case it is deemed necessary to interconnect a DG facility with the potential to cause an adverse condition.

8.0 External Disconnect Requirement – Small DG Threshold Size

8.1 National Grid

For independent power producers and non-independent power producers:

- Interconnections greater than or equal to 25kW

8.2 Eversource MA

External Disconnects are required for all sizes.

8.3 Unitil

DG > 10kW

9.0 Witness Test Protocols

9.1 National Grid

National Grid requires witness testing of the Customer redundant relaying, where such relaying is required by the project conditions. Where redundant relaying is not required, National Grid requires testing of generator internal relaying, as well as certification by a nationally recognized testing laboratory (NRTL) that employs UL1741 testing standards. The Witness Test must be conducted by a third party, and attended by a Utility representative for supervision and approval of results. National Grid's service bulletin ESB 756C provide a sample witness test.

9.1.1 Required Documentation

- Witness test procedure
- Energization plan
- Current single line diagram
- Relay settings

9.1.2 Minimum Required Test Points

Relay set-points should be specified in accordance with IEEE 1547. Underfrequency ride-through should be modified according to the NPCC A.03 curve. Clearing times include breaker operation.

- 27 Undervoltage
- 59 Overvoltage
- 81o/u Overfrequency, Underfrequency
- 51N Neutral Overcurrent (where applicable)
- 51C Phase Overcurrent (Voltage-Controlled)
- 59N Neutral Overvoltage (where applicable)

9.2 Eversource MA

Installations 200kw and greater need a witness test. Under that size we can accept a photo, of the array, inverter and exterior disconnect switch.

Witnessing of Commissioning Test

Company inspects completed installation for compliance with requirements. The Company reserves the right to require a Witness Test of all facilities as approved by the Company. The Interconnecting Customer will provide a proposed Witness Test procedure and all requisite supporting documentation for review by the Company once the Interconnecting Customer has completed the installation of the Facility.

Testing typically includes, but is not limited to:

• CT and CT circuit polarity, ratio, insulation, excitation, continuity and

burden tests.

• VT and VT circuit polarity, ratio, insulation and continuity tests.

• Relay pick-up and time delay tests.

• 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 deadlines.

• Certified test results

• Final Approved Relay settings including inverter settings if applicable

• Final Drawings (onelines, threelines, schematics, etc)

• Failure protocol - In the event of a failed witness test (i.e. test results of a relay function fall outside of a certain tolerance), the witness test is rescheduled, and the failed elements are retested.

Each commissioning 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.

9.2.1 Required Documentation include but not limited to

- Witness test procedure
- Energization plan (including interlocks, operational procedures, etc.)
- Current PE stamped single line diagram
- Relay settings
- Relay Bench test results (if applicable)

9.2.2 Required Test Points

Relay set-points should be specified in accordance with IEEE 1547. Underfrequency ridethrough should be modified according to the NPCC A.03 curve. Clearing times include breaker operation.

- 27 Undervoltage
- 59 Overvoltage
- 81o/u Overfrequency, Underfrequency
- 51N Neutral Overcurrent
- 51 Phase Overcurrent
- 59N Neutral Overvoltage

9.3 Unitil

Witness testing for Simplified Track projects, is not required by Unitil as long as the facility owner provides adequate photos of the system and meter. For non-Simplified projects, the applicant must provide the proposed test procedure for approval prior to Unitil witnessing the commission test.

9.3.1 Required Documentation

- Witness test procedure

9.3.2 Required Test Points

Relay set-points should be specified in accordance with IEEE 1547. Fast response clearing times (e.g. 0.16 sec.) include breaker operation.

- 27 Undervoltage
- 59 Overvoltage
- 81o/u Overfrequency, Underfrequency
- 51N Neutral Overcurrent
- 51 Phase Overcurrent
- 59N Neutral Overvoltage

9.4 Failure Protocol (Common)

In the event of a failed witness test (i.e. test results of a relay function fall outside of a certain tolerance), the witness test is rescheduled, and the failed elements are retested.

10.0 Inverter Power Factor Requirements

10.1 National Grid

All generation is required to maintain a power factor at the point of common coupling in accordance with the MA-SIDG between 0.90 leading or lagging.

DG may provide static power factor regulation at the PCC. If the circuit has no voltage regulators, the DG may provide active power factor regulation at the PCC.

10.2 Eversource MA

Unity power factor required as the DG terminals. However Eversource reserves the right to require off unity power factor due to our own operating requirements or those of a regulatory body such as ISO-NE.

Unitil

+/- .95

11.0 Interface Transformer Winding Configurations

The following section describes transformer winding standards for effectively-grounded systems. In all service territories, neutral grounding reactors may be required in the event that existing grounding fault detection is compromised by the addition of DG. Each utility maintains a handful of ungrounded circuits, for which alternate winding configurations may be acceptable. For 4-wire, multi-grounded circuits, the preferred transformer configurations are:

11.1 National Grid

11.1.1 Approved Winding Configurations

In the following, the primary side is considered to be the utility side and the secondary side is considered to be the customer side:

- Primary Wye-grounded; Secondary delta (neutral ground reactor)
- Primary Wye-grounded; Secondary wye-grounded (with effectively grounded DG source)
- Primary Wye-grounded;Secondary wye-grounded (with secondary grounding transformer)
- Primary Delta; Secondary wye-grounded (with primary grounding transformer)

11.2 Eversource MA

The Company may not specify Generator Step-Up (GSU) Transformer configuration type. However, the transformer high side must be compatible with the EPS. The protection requirements listed in Eversource MA Technical Standard shall apply to all GSU types. It should be noted that the Customer's engineer shall design a protection scheme that is able to sense and isolate the Customer generation for all instances of Over/Under Voltage (27, 59), Over/Under Frequency (80/81) and Over Current (50/51) for BOTH sides of the GSU. Potential Transformers for relay application shall always be installed on the high voltage side of the GSU.

Unitil

11.2.1 Approved Winding Configurations

Wye-grounded x delta
Wye-grounded x wye-grounded (with effectively grounded source)
Wye-grounded x wye-grounded (with secondary grounding bank)

12.0 Customer Redundant Relaying

At certain facility sizes, utilities may require redundant utility-grade relaying to disconnect the generator under faulted conditions. 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). Relays must be located upstream of the grounding source, on the customer side of the PCC. For a list of required relays, refer to the Witness Test Protocols in Section 9. Customers may install motor-operated switches for remote reconnection, but are prohibited from utilizing auto-reclosing.

12.1 National Grid

- Required at DG $\geq$ 500kW
- For sites between 250kW and 500kW, it is at the discretion of the company given the unique circumstances of the interconnection as to whether or not redundant relaying is required.

12.2 Eversource MA

Redundant relaying Required for Inverters =>500kW, Asynchronous Generators =>300kW and ALL Synchronous Generators. See section 4.2 of Eversource Interconnection Standard 'Protection Requirements per Technology Size and Type'. However Eversource reserves the right to require redundant relaying for any installation in order to maintain safety and reliability.

Unitil

Required at DG $\geq$ 500kW
Protection functions provided by a Unitil owned recloser at PCC can be considered as providing redundant relay functions.

13.0 Reverse Power Flow (Substation Level)

13.1 National Grid

National Grid permits reverse power flow through the substation supply transformers. For situations where the total DG on the substation is approaching the minimum load of the substation, reverse power flow and the likelihood of the DG 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). For transmission systems less than 115kV, VT's are required. For transmission systems greater than or equal to 115kV, capacitively-couple VT's are required. Screening for the 59N requirement is accomplished through an N-1 scheme, for which the feeder with the highest net load (DG on feeder minus minimum load on feeder) is removed from the calculation. In the N-1 scenario, if the total DG to minimum load ratio of the remaining feeders is greater than or equal to 67%, then 59N is required at the substation (in N-1 case, total DG / total min load ≥ 67%)

13.2 Eversource MA

Transformer Reverse Power Capability Any proposed generation Facility that has the potential to cause reverse power flow through an Eversource substation transformer will require an Impact Study. The Impact Study will specifically address the ability of the transformer to accommodate reverse power flow. The following items will be evaluated:

System Voltage Control: The Impact Study shall determine if system voltage control can be maintained at various boundary conditions, and will evaluate excessive load tap changer ("LTC") operation caused by intermittent DG sources.

LTC Design, Controller Type and Controller Settings: The Impact Study will evaluate the capability of the LTC and controller to accommodate reverse power conditions and to respond with appropriate control strategies.

Voltage and current inputs must be available to the LTC controller. Any LTC 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. LTC upgrades may be required system modifications resulting from DG facility interconnection.

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

Capacity Limit: Intermittent reverse power flow will be permitted up to a level consistent with Eversource 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 DG Facility.

DG 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).

Eversource Energy MA Technical Specifications for DG Interconnection 3/15/16 9 As a part of the Impact Study process, projects will be reviewed on a case by case basis to determine if additional relays or other protection devices will be required. Any required protection devices will be included in system modifications required to interconnect the DG facility.

13.3 Unitil

Unitil permits reverse power flow through supply transformers that are outfitted with adequate protection (e.g. 59N) and voltage regulation schemes . In instances where primary CT’s are not viable, DTT may be used to disconnect the facility for transmission faults.

Screening for transformer back-flow is accomplished through an N-1 scheme, for which the most heavily loaded feeder on the bus is removed from the calculation. If the aggregate DG on the remaining circuits is > 0.67 * min load of remaining circuits, it is assumed that back-flow will be present.

14.0 Minimum Load Threshold for Simplified – Spot Networks

14.1 Common

DG $\leq$ (1/15)*(minimum load of customer) qualifies for Simplified

15.0 Supplemental Review Screening – Voltage Flicker (ΔV)

15.1 Common

During expedited review, voltage deviations of greater than 2% will prompt the application to be moved to a full Impact Study.