Electric System Bulletin No. 756

Distributed Generation Connected to Rhode Island Energy Distribution Facilities per the Rhode Island Standards for Connecting Distributed Generation

Version 9.0, November 2025

ESB 756 is part of the ESB 750 series

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1.0 Purpose

1. The purpose of this Electric System Bulletin (ESB) 756 *covers* requirements for interconnecting customers proposing to install a distributed energy resource (DER) system ("Interconnecting Customer" or "Customer") to Rhode Island Energy's ("the Company") Rhode Island electric power system (EPS) for State jurisdictional projects. Stand-alone generators serving isolated load, which can never be connected in parallel with the Company's EPS, are not subject to these requirements.
2. Ensure compliance with North American Reliability Corporation (NERC) Standard FAC-001-2 – Facility Interconnection Requirements, effective January 1, 2016. Along with all of the Company's ESB's. The most current version of ESB 756 is available electronically at the Company's temporary transitional website: https://gridforce.my.site.com/RI/s/article/RI-Interconnection-Documents
3. Ensure the electrical reliability and security of the Company's EPS and the larger power system grid is maintained following connection of the parallel generator to the utility supply.
4. Refer Generator-Owners or Interconnection Customers (IC) to the applicable Federal Energy Regulatory Commission (FERC) or state-specific tariff regulations pertaining to parallel generators.
5. ESB 756 *does not cover* the technical federal and state transmission operator jurisdictional requirements New England Independent System Operator (ISO-NE) and Federal Energy Regulatory Commission (FERC) for connection to the Company's transmission EPS, community microgrids, and parallel operated DER systems and on-site generators (OSG) that are covered by the Company's ESB 756 Appendix A.[1]
6. This ESB supplements **ESB 750** and the R.I.P.U.C. 2258[2] The Narragansett Electric Company Standards for Connecting Distributed Generation (**RI SCDG)**; https://gridforce.my.site.com/RI/s/article/RI-Interconnection-Documents)
7. The provides general technical requirements, recommendations, and assistance to customers regarding the DER facilities connected in parallel to the Company's distribution electric power system (Company Distribution EPS). These projects are typically 5 MWs or smaller in size. Note that the RI SCDG does not apply to DER facilities, or group of facilities, having specific requirements under ISO-NE[3] Operating Procedures No. 14 and No. 18 and where wholesale DER connections are proposed. Each DER interconnection project will be individually 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.

2.0 Scope

1. This ESB 756 is provided to assist a customer desiring to interconnect a generator facility to Rhode Island Energy's EPS to meet requirements for all generating interfacing equipment to be designed, installed, interconnected, tested, and operated in accordance with applicable government, industry, and Company standards.
2. These requirements are limited and apply to only those types of parallel generation and energy storage systems covered by the RI SCDG connected to the Company EPS with a nameplate rating of 5 MW or less including other distributed energy resources (DER) intentional and microgrid islanded systems facility or campus-style microgrids, and where DER owners, or DER owners as clients of registered aggregators, sign onto a

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[1] *If deemed as a FERC jurisdictional projects, the Customer will need to apply and work with the ISO-NE (http://www.iso-ne.com/genrtion_resrcs/nwgen_inter/index.html) for interconnection to the distribution system, following the application requirements of the FERC Small Generator Interconnection Procedure (SGIP) and ISO-NE Schedule 23.*

[2] *Rhode Island Public Utilities Commission (PUC or R.I.P.U.C.).*

[3] *Independent System Operator (ISO) for New England (NE); see https://www.iso-ne.com/.*

retail tariff with the intent to sell energy or ancillary services to the retail market. For FERC jurisdictional projects connected to the Company Distribution EPS, the technical provisions of this document will apply. Where conflicts arise, the technical provisions of ESB 756 take precedence.

3. These requirements apply only to those points in which the Customer and the Company have a mutual interest of the DER facility's or premises' wiring service connection to ensure safety to Company employees and the public as well as satisfactory operation, compatibility, and reliability with the electrical supply to others served by the Company's EPS. This includes, but not limited to:
   - The location of the service point and facilities under the Company's exclusive control, such as the Company's metering to be installed at any point on either side of the service point;
   - Service lateral;
   - Service equipment; and
   - The Company's need to automatically isolate parallel sources of the DER facility from the EPS should there be an unacceptable disturbance, event, or condition within the facility.

     Conditions of electric service are based on governmental laws or regulations that determine the Company's authority to provide electric service under their tariffs. See 90.2(B)(5) in the National Electrical Code® and the Company's ESB 750 for more information.

4. For the Company's interconnection process requirements of the RI SCDG, please refer to the retail tariff requirements at the following Company website:
   https://portalconnect.rienergy.com/RI/s/ri-process

   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, including but not limited to energy storage system (ESS) facilities, regenerative drives used in elevators, and component power inverters used in exercise equipment and any other micro-scale type energy recapture systems.

3.0 Applicable Codes, Standards and Guidelines

1. 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 bulletin include, but are not limited to:
   - Institute of Electrical and Electronics Engineers (IEEE) Std. 1547-2018 "Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces"
   - Underwriters Laboratories (UL) Std. 1741 "Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources"
   - ANSI/IEEE C2 "National Electrical Safety Code®" (NESC)
   - NFPA 70 "National Electrical Code®" (NEC)
   - NFPA 70B "Recommended Practice for Electrical Equipment Maintenance"
   - NFPA 70E "Standard for Electrical Safety in the Workplace"
   - NETA-MTS "Maintenance Testing Specifications for Electrical Power Distribution Equipment and Systems"

2. The Customer's DER facility shall also conform to any applicable requirements of the Rhode Island PUC and any local, state, federal and/or other agencies from which a review, approval, or a permit is required.

    - The minimum "fall zone" clearance of wind turbine generators (WTG) shall be in accordance with the local governmental authority having jurisdiction (AHJ) and in any case, shall not be less than 125% of maximum WTG height measured horizontally to the Company's overhead distribution lines.

    - Refer to ESB 750 for additional information regarding specifications for electrical installations. The Customer is responsible for securing and coordinating all required easements and permits for installation of equipment on the proposed site.

3. The Customer shall comply with the latest revision of the appropriate Company ESB or tariff requirements, which cover details for the Customer's electric service installation. These include:

    - **ESB 750** - Specifications for Electrical Installations
    - **ESB 751** - General Requirements Above 600-Volt Service[4]
    - **ESB 754** - Outdoor Pad Mounted or Vault Enclosed Single and Three Phase Transformer
    - **ESB 757** – Network Services
    - **ESB 759A** – Underground Residential Distribution (URD) Installation & Responsibility Guide
    - **ESB 759B**– Underground Commercial Distribution (UCD) Installation & Responsibility Guide
    - **R.I.P.U.C. 2258** - The Narragansett Electric Company Standards for Connecting Distributed Generation (RI SCDG)**R.I.P.U.C. 2243** - The Narragansett Electric Company Terms and Conditions for Distribution Service
    - **Net Metering Tarriff RIPUC 2268** – Net Metering Tariff Provision
    - **NET Metering Provision** - The Narragansett Electric Company Net Metering Provision
    - **R.I.P.U.C. 2151-K**- The Narragansett Electric Company Renewable Energy Growth for Residential Customers
    - **R.I.P.U.C. 2152-K** - The Narragansett Electric Company Renewable Energy Growth for Non-Residential Customers
    - **R.I.P.U.C. 2256** – The Narragansett Electric Company Qualifying Facility Power Purchase Rate

    Refer to Exhibits 4 and 5 and Figures 1 through 3 for information when submitting single-line diagrams to the Company's electronic mail address at Distributed.Generation@rienergy.com.

4.0 Definitions

See ESB750, ESB756, and the **RI SCDG** for definitions of special terms. The following terms are defined for the purposes of this document. for definitions of special terms. The following terms are defined for the purposes of this document.

1. **Certified:** Equipment that is approved by examination for safety; see NEC Articles 90 and 110.

[4] *ESB 751 Applies regardless of service voltage for DER systems.*

2. **Certified DER:** A Distributed Energy Resource that uses inverter technology and has been tested and certified to UL 1741-SB 3rd Edition by a Nationally Recognized Testing Laboratory, whose OSHA Scope of Recognition includes UL 1741.

   Note 1: Certified DER shall be installed according to the Manufacturer's installation instructions. Any deviation from the instructions may change the certified performance characteristics and is therefore not allowed.

   Note 2: For the remainder of this document, these resources will be referred to as "1741-SB" and shall comply with the "Default IEEE 1547-2018 Settings Requirements", dated Dec 13, 2022, and shall comply with IEEE 1547-2018 Category III abnormal operating performance requirements, and Category B reactive power capability and voltage regulation performance requirements.

3. **Distributed Energy Resource:** A source of electric power that is not directly connected to a bulk power system. DER includes both generators and energy storage technologies capable of exporting active power to an EPS. An interconnection system or a supplemental DER device that is necessary for compliance with IEEE 1547 is part of a DER.

4. **Distributed Energy Resource Management System (DERMS):** Visibility and control systems aimed at helping utilities integrate DER with operations for dynamic management and monitoring purposes.
5. **Generator**: Equipment that produces power.
6. **Generator Set** or **Genset**: The singular assembly of an electrical generator and a prime mover.
7. **Line section**: Any EPS circuit segment that can be isolated via an automatic interrupting device such as a sectionalizer, recloser, or circuit breaker on three phase circuits; fuses and cut-out mounted reclosers on single phase ground circuits.
8. **Microgrid Interconnection Device (MID):** A device capable of allowing a DER to separate from the Area EPS source and transition to standalone mode.
9. **Multimode Inverter:** An inverter that has both standalone and utility interactive capabilities.
10. **Non-certified DER:** Any induction or synchronous DER, or non-UL 1741 inverter. Non-certified DER comply with the Default IEEE 1547-2018 Settings Requirements, dated May 9, 2022, and shall comply with IEEE 1547-2018 Category I performance requirements. All non-rotating generation applications shall be Certified DER except by special case to be presented to the Company at the time of application and exception made at the Company's discretion.
11. **NRTL:** Nationally Recognized Testing Laboratory, as defined by OSHA.
12. **Prime Mover**: The equipment that drives the generator to output power. For example, in a typical motor operated generator, i.e., M-G set, the motor would be considered the prime mover, or for photovoltaic installations the DC panel arrays on a solar facility would be considered the prime mover.
13. **Recloser:** A line protective device having automatic interruption and controlled reclosing characteristics.
14. **Reference Point of Applicability (RPA):** The location where the interconnection and interoperability performance requirements specified in IEEE-1547 apply.
15. **Secondary:** The Company's distribution systems typically operating at 600V or below.
16. **Service:** The conductors and equipment for delivering energy from the Company's distribution line to the wiring system of the Customer served.
17. **System Impact Study (SIS):** An engineering study performed by the Company that identifies potential problems with a requested interconnection, in accordance with

Industry Standards, the Company's Planning Criteria, Construction Standards, and relevant ESBs, and allows the Company to determine corrective modifications to the Area and Local EPS.

18. **Utility Grade:** Refers to protective device equipment complying with ANSI/IEEE C37.90, ANSI/IEEE C37.90.1 and ANSI/IEEE C37.90.2.
19. **Point of Common Coupling (PCC):** The point of connection between Company's EPS and Customer's EPS.
20. **Point of Interconnection (POI):** The point where the Customer's Facility connect with the existing Company's EPS. This may or may not be coincident with the point of common coupling.
21. **Point of DER Connection (PoC):** the point where the DER is electrically connected to Customer's EPS.
22. **Power Plant Controller (PPC):** A Power Plant Controller is used to regulate and control any combination of inverters, generators, supplemental devices, and associated equipment at a DER plant in order to meet specified setpoints and requirements at the RPA, as defined by IEEE 1547.

The terms Customer, distributed generator (DG), distributed resource (DR), interconnecting customer (IC), and isolated are defined in the **R.I.P.U.C. 2258** Interconnecting Customer Interface Procedures

5.0 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 distribution EPS. [5] This process is intended for the following:

1. New DER facilities (as aggregated on the customer side of the point of common coupling (PCC)), that are eligible under the **RI SCDG** process and;
2. Review of any modifications affecting the Company distribution EPS and service connection interface at the point of common coupling (PCC) of existing Customer DER facilities that:

   (**i**) Have a nameplate rating of 10 MW or less as aggregated on the customer side of the PCC;

   (**ii**) Are eligible under the SCDG process; and

   (**iii**) Have been interconnected to the Company EPS where an existing retail interconnection agreement and/or power purchase agreement between the Customer and the Company is in place; and

   This application process and its requirements do not apply to generation equipment that will never be allowed to operate in parallel with the Company Distribution EPS. For example, this process does not apply to emergency standby generators with break-before-make transfer switches and any other generation sources that operate independently of any connection to the Company Distribution EPS and have no provision for such connection (even for a short period of time).

   As stated above, this application process is mandated by the Rhode Island Department of Public Utilities (DPU) for customer generation equipment that will be connected to the Company Distribution EPS on a full or part time basis; see the **RI SCDG**.

[5] *If the Company approves an application to interconnect a DER facility to the Company's distribution EPS, the terms and conditions of that approval will be set forth in an Interconnection Service Agreement, which is a legally binding document that can only be changed by a written document signed by both parties. See Exhibits H and I in the* **RI SCDG**.

5.1.1 Interconnected Customer Technical Data Submission

The Customer shall submit, at the time of application, all relevant documentation as indicated in R.I.P.U.C. 2240. The Company reserves the right to request additional information as needed specific to the interconnection of Customer equipment including, but not limited to, one-line diagrams, control diagrams, equipment test reports and other information; see the Company's ESB 750 and 751. The Customer shall provide proof of land ownership or rights to land use.

5.1.2 Control Diagrams

The Customer shall submit all control diagrams ("DC control schematics") of the equipment associated with the interconnection protective system. Control diagrams depict all logic used to control the interconnection protective devices. Relay logic diagrams shall be provided for utility-grade relay functions meeting utility requirements.

5.1.3 Interconnection Facility Equipment Data Sheets

The Customer 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 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:

1. Rotating machine impedance parameters for modeling
2. Inverter-based system models and validation test data
3. 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
4. For 5 MW or greater inverter-based DER, Customer is required to provide a stability model. Please see ("Guideline for Modelling Inverter-Based DER Greater Than or Equal To 5MW").

5.1.4 Site Plan

A site plan shall be submitted 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 show the following equipment at minimum:

1. Site Plans shall be stamped by a Professional Engineer in the state of the project. Stamp shall be dated, and the date must be after all changes are permanently affixed to the diagram.
    a. If changes are made that affect the electrical functionality of the system, Stamps shall be required at:
        i. Time of application
        ii. Final Company acceptance at the 20 BD review
        iii. Final Company acceptance at the 50 BD review
        iv. As-built / Witness Test acceptance
2. Interfacing transformers
3. Interrupting devices
4. Isolation device(s) (e.g. Generator Disconnect)
5. Point of Common Coupling (PCC)
6. Restricted access, fences, gates and access controls
7. Existing and proposed Access road(s) including, at a minimum, road material, surface loading criteria, and dimensions to confirm Company personnel and equipment access requirements are met.
8. Generator location

9. Existing service(s)
10. For OH Interconnections:
    a. Company pole number nearest the proposed PCC
    b. Company line extension to site and from nearest POI
11. For UG Interconnections:
    a. An area designated for Company pad mounted equipment equivalent to 750-1500 sqft (actual to be determined during System Impact Study)
12. Refer to ESB 759B "Underground Commercial Distribution Installation and Responsibility Guide"

Site plans shall be to scale with approximate distances indicated, north arrow and scale bar. In addition to site plan, the Company may request an assessor survey map to determine property lines, wetlands and easements. The Customer should consult the Town By-Laws regarding overhead versus underground interconnection requirements when developing the site plan. The Customer's site plane shall indicate proposed Utility equipment or pole locations for coordination. Locations of company equipment shall be noted as: "For information purposes only. Final location determined by Utility". Final location of Company equipment is determined by the Company, typically during the design and construction phase.

5.1.5 Data Required for Energy Storage System Applications

For applications having ESS proposed, additional information may be required at the time of application for interconnection such as but not limited to:

1. Method of ESS connection whether: (1) ESS directly connected to utility EPS; (2) Distributed Generator (DG) and ESS DC coupled; (3) DG and ESS AC coupled; and (4) ESS on load side of service point and utility revenue meter with the premises load, as applicable to the proposal.
2. Sequence of operation for the ESS' charging and discharging capabilities including daily, monthly, and/or seasonal schedules (see Table 7.8.2.2-1)
    a. A narrative of how the operation schedule shall be executed from an equipment and control logic perspective shall be supplied at the time of application and notes included on the one-line.
3. The maximum ramp rate in Watts/second. (Note RIE targets 2% ramp rate of total capability)
4. Non-UL 1741 listed inverters will require a utility intertie relay with the appropriate IEEE 1547-2018 functions, settings, and islanding protection according to the Company's ESB 756 jurisdictional requirements.
5. Service configuration and revenue metering provisions shall meet the Company's ESB 750 and its applicable supplements.

5.1.6 Data Required for Facility or Campus-style Microgrid Applications

Additional information may be required at the time of application for interconnection specific to the facility or campus-style microgrid proposed operation, such as but not limited to:

- Any and all existing conductor types, lengths, and numbers of sets, including conductor material and insulation systems, between the PCC and PoC.
- Any and all existing transformer size, voltage, and impedance data between the PCC and PoC.
- Any and all fuses, relays, and other protective devices between the PCC and PoC including settings.

- Any and all specifications of controllers, automated switching, and operating modes relating to the control of the Customer's Local EPS. If equipment specifications are not available at the time of application, a narrative describing the intent of the control system may be provided so the application can be sufficiently studied during the impact study.

Facility or campus-style microgrid applications have certain characteristics described here, all of which fall under the U.S. Department of Energy (DOE) definition.[6] Such microgrids consist of one or more buildings and the relationship with the interconnected utility is characterized as either a single customer-of-record or a single operating entity on one property. These can take several forms such as:

1. A single building under a common property owner with a common customer account. The microgrid has generation resources that can operate in parallel with the electric grid or in island mode.
2. A single building under a common property owner/customer, with multiple direct-metered accounts. The microgrid is configured so that all customers within the building can share the benefits of DER.
3. Multiple buildings owned by a common property owner where microgrid loads and DER are tied with common electric distribution facilities generally not owned by the utility.

These facility or campus-style microgrids are premises wiring systems governed by the National Electrical Code (NEC) as adopted by the local jurisdictional authority.[7]

5.1.7 One-line Requirements

DER Customer's must submit one-line diagrams per the following requirements:

1. One-line shall make use of IEEE 414 Standard Symbols and IEEE C37.2 for relay device numbers.
2. One-lines shall be stamped by an Electrical Professional Engineer in the state of the project. Stamp should be dated and date must be after all changes and permanently affixed to the diagram.
    a. Stamps shall be required at:
        i. Time of application
        ii. Final Company acceptance at the 20 BD review
        iii. Final Company acceptance at the 50 BD review
        iv. Asbuilt / Witness Test Acceptance
3. One-line files submitted to the Company:
    a. Revision Block shall be up to date,
    b. Changes from previous revision shall be highlighted.
    c. Shall use the File Naming Convention: Case#*xxxxxx*_Oneline_Revision#*xx*_*(Date-Submitted)*
4. Clearly identified Point-of-Common-Coupling (PCC) and Point-of-Connection (POC) per IEEE 1547 standard definitions. The Reference Point Applicability (RPA) is the PCC location unless otherwise determined through consultation with the Company.
5. One-line shall show any generators with the following information: ratings in kW and kVA. Any de-rating shall be clearly noted. See Section 7.0 for more requirements.
    a. If Inverters are used: Make, model, UL1741 Certification of any and all inverters. See Section 7.6 for more requirements.

[6] *The U.S. DOE defines a microgrid as a "group of interconnected loads and distributed energy resources (DER) with clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid [and can] connect and disconnect from the grid to enable it to operate in both grid connected and island mode."*

[7] *See NFPA 70-2017 NEC for installation requirements of premises wiring systems related to microgrids.*

    b. If Synchronous or Induction Generators are used: Make, model, and winding/grounding arrangement. See Section 7.6 for more requirements.
6. One-line shall show the Service Entrance Equipment, with the following information: voltage, continuous current, and interrupting current ratings. See Section 7.2 for more requirements.
7. One-line shall show any Step-Up Transformation, with the following information: high and low side voltages, winding configuration, kVA rating, impedance in Z%, and X/R ratio. See Section 7.3 for more requirements.
8. One-line shall show Means of Effective Grounding (if applicable), with the following information: acceptable configuration, acceptable interlock scheme, as per Section 7.3.2.1.
    a. If Grounding Transformer is used: kVA ratings, impedance rating in ohms per phase. See Section 7.1.5 and 7.3.2.1 for more requirements.
    b. If Grounding Reactor is used: continuous current ratings, impedance rating in ohms. See Section 7.1.5 for more requirements.
9. One-line shall show the Manual Generator Disconnect, with the following information: Type and Make, Location that allows 24/7 access by the Company. See Section 7.4 for more requirements.
10. One-line shall show the Generator Interrupting Device, with the following information: voltage, continuous current, and interrupting current ratings. See Section 7.5 for more requirements.
11. One-line shall show the Secondary Protection Current Transformers, with the following information: CT ratio, accuracy rating and class, thermal rating factor, and burden. See Section 7.6.4.1 for more requirements.
12. One-line shall show the Secondary Protection Potential Transformers, with the following information: PT ratio, accuracy rating, thermal rating, burden, and winding configuration. See Section 7.6.4.2 for more requirements.
13. One-line shall show Secondary Protection Relay, with the following information: Make, Model, and relay accuracy.
    a. If relay is being used in a power limiting scheme, one-line shall show relay minimum sensitivity.
14. One-line shall show any RTU circuits, if required. See Section 7.7 for more requirements.
15. One-line shall show any DTT circuits, if required. See Section 6.2.1 for more requirements.
16. One-line shall show any controllers/associated control circuits and description of operating modes. If a control narrative was provided, notes from the narrative shall be included on the one-line.
17. One-Line shall show any Battery Energy Storage System, with the following information: ratings in kW and kWh, any battery management system. Any schedule and/or curtailment factors that are the result of the Impact Study analysis shall be included at the 50 BD review. See Section 7.7.3 for more requirements.
18. One line shall show primary and secondary protection.
19. Projects with 1741-SB inverters the followings must show in the one line
    a. Certified to UL 1741 SB Edition 3 or UL1741 Edition 3 certification is pending.
    b. Advanced inverter settings (specifically frequency-watt settings).
    c. Mode of operation for each voltage and frequency ride through region.
    d. In addition to all protection elements, one-line must show if rate of change of frequency (ROCOF) and/or voltage phase angle change protections are enabled.

5.1.8 Grid Modernization DER Monitor/Manage Technology Requirements

The Company envisions the need for a DER Monitor/Manage system to maximize the deployment of renewable resources, energy storage, and flexible loads. To explore this concept, the Company is assessing the legal and regulatory approvals necessary to permit DER Monitor/Manage and will make a separate filing for such approvals, including any tariff changes.

Although the Company is not requiring control of the DER resources at this time, the Company requests that at the time of application the DER customer provide information on:

- Spare Ethernet 16 or a Serial (RS-485) interface communication ports
- Communication protocols aligned with Section 10.2 of IEEE 1547-2018, including use a unified information model, and non-proprietary protocol encodings based on international standards or open industry specifications such as:
  - SunSpec Modbus;
  - DNP3 (IEEE 1815);
  - SEP2 (IEEE 2030.5)

5.1.9 Moderate/Significant Changes

As part of the interconnection process, customers may request to make changes to their designs at any time. These changes are to be assessed by Rhode Island Energy to determine whether the change is Significant or Moderate. The following defines these terms and the associated impacts to the DG application.

1. Significant change: A change is considered significant if it meets EITHER of the following criteria:
   a. Customer impact: Results of studying the change may have an adverse impact to other customers in queue. Examples of effects to others in queue include, but are not limited to reducing electrical capacity availability, causing the need for new cost obligations, causing delay to either study or construction timelines, etc.
      i. OR
   b. Engineering Impact: The change modifies the fundamental design intent of the original application to such an extent that majority of the engineering analyses of the original SIS must be re-performed (ex. Load flow, protective device analyses, substation assessment, etc.)
2. Moderate Change: A change is considered Moderate if it meets BOTH of the following criteria:
   a. Customer Impact: The change has no possibility of impact to other customers. Either confirmed through the fact that no other applications are after the subject project in queue or confirmed by engineering review of the proposed change.
   b. Engineering Impact: The change modifies the original application requiring performance of engineering analyses of the original SIS to be re-performed (ex. Load flow, protective device analyses, substation assessment, etc.)

5.2 Interconnection Process for DER Not Eligible for the Simplified Process

The process for installation of those facilities the Company deems necessary for interconnection of the DER system will be specified by the Company in accordance with the **RI SCDG** in response to the Customer's DER interconnection application. See **Exhibit 1** for Company requirements for Projects not Eligible for the Simplified Process.

5.3 Objectives in the Application Process

1. Parallel operation of a generator becomes integrated with the Company EPS, in which the Customer and the Company have a mutual interest. The interconnection must preserve the safety, reliability, security, power quality, and operational efficiency needs of the Company's EPS. This is necessary to ensure safety to the public and to Company employees and satisfactory operation and compatibility with the electrical supply to others. The steps and timing requirements of the application process are identified within the **RI SCDG**.
2. Additional site-specific requirements may be indicated once the supply voltage, service arrangement, location, and generation purpose are determined, where such Customer proposed purpose can be either:
   - Peak shaving,[8]
   - Net energy metering for solar, wind, anaerobic digestion, small hydroelectric, or agricultural or other projects in accordance with the Company's net-metering tariff, RIPUC 2258,
   - Renewable Energy Growth (REGrowth Program) according to RIPUC 2152-K (for Non-Residential Customers), or RIPUC 2151-K (for Residential Customers), or
   - export energy for a QF with an agreement for sales[9] all according to the Company's tariff provisions.
3. For new electric service or modifications to the electric service connection to accommodate the Customer's DER system, refer to the Company's latest revision of ESB No. 750, Specifications for Electrical Installations. 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. For example,
   - Under RI and municipal building code requirements the Customer will need to provide evidence of electrical inspection approval from their local municipal code enforcement agency.
   - The Customer will also be responsible for any additional costs associated with work completed by another entity (such as Telco set poles). The Customer should be aware that project construction schedules can be severely impacted by this other work.
4. When considering a DER interconnection arrangement, an R.I.P.U.C. 2258 Exhibit A or B application is submitted to the Customer Energy Interconnection (CEI) department.
5. Any subsequent sale of an On-Site Generator (OSG) facility covered by the requirements of the RI SCDG of the original retail Customer's facility will require the new owner to establish a separate interconnection agreement (R.I.P.U.C. 2258 Exhibit G and/or H) for the generation and to comply with these parallel generation requirements.
6. Refer to:
   - The steps to install distributed generation in Rhode Island as specified in the RI SCDG; see Section 3.0 of R.I.P.U.C. 2258
   - The Company's Distributed Generation Services **electronic mail address** as follows for inquiries: Distributed.Generation@rienergy.com, and

[8] *Peak shaving generation is Customer-owned generation operated in parallel with the Company to reduce a Customer's electrical demand. Unlike net metering, peak shaving generation is not permitted to flow into the utility supply system upstream of the billing meter and will require the installation of protection devices to limit such power export onto the Company's EPS. The Company's revenue metering is detented in this case to prevent reverse billing meter registration.*

[9] *An Agreement for Sales of Export Energy for a QF under a RI SCDG application may be made per the Company's R.I.P.U.C. 2098 electric tariff and is a Power Purchase Agreement.*

- The Company's (https://portalconnect.rienergy.com/RI/s/article/RI-Interconnection-Documents) "Distributed Generation" web site at for information and forms listed below (from R.I.P.U.C. 2258) when making an application with the Company:

    - Simplified Process application form and service agreement (Exhibit A)
    - Generating Facility Expedited/Standard Pre-Application Report Form (Exhibit B)
    - Expedited and Standard Process application form (Exhibit C)
    - Supplemental Review Agreement (for those projects which have failed one or more screens in the Expedited Process) (Exhibit D)
    - Feasibility Study Agreement (Exhibit E)
    - Impact Study Agreement or Impact Study for Renewable DG (ISRDG) Agreement under the Standard Process (Exhibit F)
    - Detailed Study Agreement (for the more detailed study under the Standard Process which requires substantial System Modifications) (Exhibit G)
    - Schedule B Additional Information Required for Net Metering service
    - Interconnection Service Agreement (Exhibit H)
    - Agreement between the Company and the Company's Retail Customer (Exhibit I)

- The following Independent System Operator-New England (ISO-NE) requirements apply under this bulletin:
    - DER projects 60 kW or larger that will export power require asset registration by the Company's Customer Energy Integration (CEI) department to ISO-NE.
    - DER projects greater than 1 MW but less than 5 MW will require a notification by the Company's CEI department to ISO-NE via Attachment 4 under ISO-NE Planning Procedure (PP) 5-1.
    - DER projects 5 MW and greater, in aggregate, will require a review of transmission system impacts and a Proposed Plan Application (PPA) filed with ISO-NE. Refer to ISO-NE PP 5-1. A backup alternate means of communication will be required to be connected to the Company's Transmission Management System and will be captured in the System Impact Study.

7. 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. As allowed by the Rhode Island PUC, the costs of the detailed study and upgrades are the responsibility of the Customer. If the Customer makes significant changes in the design or scheduling of their DER project, 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.
8. The following website contains the Company's application of the RI SCDG net metering rules: https://portalconnect.rienergy.com/RI/s/ri-incentives-and-programs

5.4 Special System Considerations

The Company will identify in the DER impact study any systems that may require special considerations including but not limited to those in this section.

5.4.1 Secondary Grid and Spot Network Areas

1. When applying for a DER interconnection within the Company's secondary area network and secondary spot network EPS located in the downtown districts of Pawtucket and Providence in Rhode Island, DER installations on distribution secondary network systems may require a study to be undertaken to ensure the DER facility does not degrade the reliability, power quality, safety, or operation of the Company's network system. For these areas, the study may be required regardless of DER size, type, or complexity. Therefore, customers in the downtown districts of Pawtucket and Providence **should check the** Rhode Island Energy Website: "Area Network Maps" [PPL Rhode Island DG System Portal. **If that street location is highlighted in red (or near) the red line, then contact the Company at** (Distributed.Generation@rienergy.com) to determine if the proposed location is served by a distribution secondary network system. This should be done while the project is still in the planning stage, and certainly before purchasing equipment or beginning installation. The Company's CEI department will review the Customer's plans and discuss options with the Customer. Refer to attached Exhibit 2 for area maps locating the Company's secondary network service areas.
2. Unlike radial distribution systems that deliver power to each customer in a single path from source to load, underground secondary area network systems deliver power to each customer through a complex and integrated system of multiple transformers and underground cables that are connected and operate in parallel; refer to attached **Exhibit 3** for more information.
   A. Connecting customer DER to the low voltage secondary networks can cause the power flow on network feeders to shift (i.e., reverse) causing network protectors within the network system to trip open. The Company's network system protection is designed without time delay. Synchronous generators are not permitted to interconnect to the Company's secondary voltage network systems. Small induction and inverter-based generators are considered on the secondary voltage network systems on a case-by-case basis.
   B. Spot networks are similar to area networks except they serve a single premise. Connection of DER systems on the spot networks are only permitted if the secondary bus is energized by more than 50% of the number of installed network protectors as required by the current version of the IEEE Std. 1547-2018.
   C. As a result, the connection of customer DER facilities on networks **(i)** poses some issues for the Company to maintain adequate voltage and worker safety and **(ii)** has the potential to cause the power flow on network feeders to shift (i.e., reverse) causing network protectors within the network grid to trip open. Therefore, to ensure network safety and reliability additional information will be required for the Company's engineering analysis such as:
      - Customer's existing[10] or proposed electric demand profile showing minimum load during peak generation time,
      - Customer's expected generation profile shown for a 24-hour period and typical seven (7)-day duration based on nameplate generation rating, and
      - Customer's complete electric service single-line diagram showing the configuration of the proposed generation and other metered tenants, if any, up to the service point supplied by the Company's secondary network EPS.

5.4.2 Less than 5kV Distribution Systems

Due to the existing limitations and company requirements for 4kV systems, DER interconnections equal to or greater than 100 kW that are proposed to interconnect to

[10] *In addition, the Company may need to install recording equipment at all metered electricity users to determine the total demand of the building's network service when obtaining the service connection's electric demand profile. The cost to the Customer will be according to the Company's electric customer load survey flat rate and charged in accordance with the terms of the RI SCDG.*

the 4kV EPS require a System Impact Study. Any DER customers proposing to interconnect greater than 300 KVA, are no longer be permitted to interconnect to the 4 kV system.

5.4.3 Non-Effectively Grounded Systems

DER installation to non-effectively grounded systems may require a study regardless of DER type, size and complexity.

All interconnections (regardless of size) to non-effectively grounded systems shall be non-effectively grounded with zero sequence overvoltage (59N) ground fault protection, which commonly requires conversion to a primary metered service – requirements for which are determined in the impact study. Interconnections proposed to connect to this system and portions of other systems built like this one may require engineering analysis in accordance with the company's Tariff regardless of size. Please see the **Non-Effectively Grounded Feeder FAQ**, for more information.

5.4.4 Multiple Service Agreements

For multiple service requests (i.e. load service with separate IPP service), additional documentation may be required. Customer shall provide site plan that shows all service equipment grouped at one location and permanently marked. Site plan shall show a Company owned point of disconnect per parcel.

5.4.5 Campus Systems

Campuses present a unique challenge to the interconnection process. A typical campus is defined as a privately owned geographic area, consisting of multiple separate buildings, that is supplied from a privately-owned electrical distribution system, or Local EPS. There will typically be one PCC between the Area EPS and this Campus Local EPS. Challenges arise when the DER penetration level of the Campus begins to trigger effective grounding (Section 7.1.5.1), 59N (Section 7.1.5.2), visibility and control requirements (Section 7.7.2). The Campus Owner may decide to aggregate these functions across the entire campus. Aggregation, gateways are emerging technologies at this time and will require increased partnership between the Company and Customer. See Section 5.1.1.5 for additional requirements.

5.5 Interconnection Charges

Customers shall be subject to charges for interconnection costs. To permit interconnected operations with a Customer, the Company may incur costs in excess of those it would have incurred had the Customer taken firm service. These costs, called interconnection costs, are directly related to the installation of those facilities the Company deems necessary for interconnection. They include initial engineering evaluations, 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 prior to commencement of service in accordance with the Company's tariffs, R.I.P.U.C. 2258 and 2243. For typical Company interconnection cost items expected in DER projects that will be defined in either an Impact or a Detailed Study, see the following two tables. Tables are not intended to be all inclusive. Costs will be determined according to the Company's electric tariff and the RI SCDG.

Table 5.5-1: DER Projects where no EPS upgrades are expected

Item No.	Typical Company Support Activities Attributed to Customer's Project Requiring Charges to the Customer)
1	Engineering acceptance review of Customer's construction design submittals where the Company has mutual interest such as service connection facilities, meter mounting provisions, Company-designated protective devices and control schemes according to the Company's ESB 750 series.
2	Revenue metering equipment changes/additions.
3	Field audit of Customer installation to accepted design.
4	Field compliance verification - witness tests of Customer protective devices coordinating with the Company Distribution EPS.
5	CEI Project Management

Table 5.5-2: Complex DER Projects

Item No.	Typical Company Support Activities Attributed to Customer's Project Requiring Charges to the Customer)
1	Company Distribution EPS upgrades (e.g., Current Limiting Fuses, Primary Conductors, Line Reclosers, Switches, Voltage Regulators, Capacitors, etc.) as a result of DER impact.
2	Where Local EPS anti-islanding protection is required, Direct Transfer Trip (DTT) transmit addition to Distribution EPS substation feeder breaker (and/or Line Recloser) for DER impact on distribution feeder.
3	Where Company-provided Radio Communications can be applied, additions to support DTT equipment at Distribution EPS substation feeder breaker (and/or Line Recloser) for DER impact on distribution feeder.
4	Where Local EPS feeder selectivity may require prompt control measures for DER impact on distribution feeder operations, EMS-RTU (status & control) addition at the DER facility.
5	Service Connection modifications and additions for DER impact on the Company Distribution EPS.
6	Revenue metering equipment changes/additions.
7	Engineering acceptance review of Customer's construction design submittals where the Company has mutual interest such as service connection facilities, meter mounting provisions, Company-designated protective devices and control schemes (e.g., DTT receive package installation at DER) according to the Company's ESB 750 series.
8	Field audit of Customer installation to accepted design.
9	Field compliance verification - witness tests of Customer protective devices coordinating with the Company Distribution EPS.
10	Project Management (CEI, Distr. Line, Distr. Station, etc.)

6.0 Potential Issues Related to Interconnection

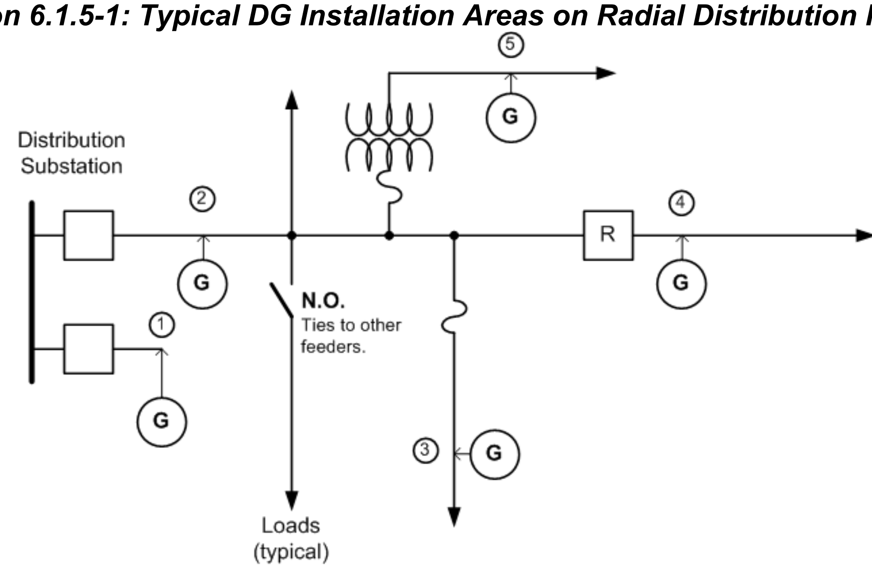
6.1 General Considerations

1. Customer generation connected to the distribution system can cause a variety of system impacts including steady state and transient voltage changes, harmonic distortion, and increased fault current levels. Parallel generation systems, which located individually on higher capacity feeders may not cause very serious impacts, can, on weaker circuits, in aggregation or in special cases (such as lightly loaded networks), significantly impact the Company's distribution EPS.
2. An Impact Study and a Detailed Study in some cases is needed to identify the severity of system impacts and the upgrades needed to avoid problems on the Company EPS. Typically, an Impact or Detailed Study will be performed by the Company to determine if the proposed generation on the circuit results in any relay coordination, fault current, and/or voltage regulation problems.
3. There is a wide range of potential issues associated with the interconnection of DER facilities to the Company Distribution EPS including, but not limited to:
   a. Impact on step voltage regulation equipment
   b. Increased fault duty on Company and Customer protective devices and equipment
   c. Interference with the operation of protection systems
   d. Harmonic distortion contributions

e. Voltage flicker
f. Ground fault over voltage
g. Risk of islanding
h. System restoration
i. Power system stability
j. System reinforcement
k. Metering
l. Arc Flash

4. It is important to scrutinize the interconnection of Customer DER facilities to the Company EPS so that any negative impacts to the Company EPS performance can be avoided without degradation of EPS safety and reliability. It is the intent of any Company study in accordance with the RI SCDG requirements when applicable to avoid negative power system impacts by identifying the particular type of impact that will occur and determining the required equipment upgrades that can be installed to mitigate the issue(s).
5. In general, DG facilities connected to various locations on the radial distribution EPS (see Illustration 6.1.5-1) are initially evaluated for the maximum possible DER capacity under ideal situations that can be installed on the Company's EPS through technical screens. Where initial technical screens identify concerns on the Company's EPS, site specific system studies (e.g., available short circuit current contributions, minimum network loading in light loading seasons, voltage regulator interactions, etc.) will be required and will identify the interconnection requirements.

Illustration 6.1.5-1: Typical DG Installation Areas on Radial Distribution Feeders



"O" - DG Interconnection Location Point on Feeder

1. Express (dedicated) radial feeder
2. Feeder Main
3. Feeder Branch protected by fuse
4. Sectionalized Feeder Main
5. Feeder Branch protected by fuse with ratio transformer

6. DER saturation, such that it becomes technically infeasible to operate on the distribution feeder or line section becomes problematic when multiple proposed projects or additional proposed projects are submitted in excess of the designed capacity of major EPS infrastructure. The Company will identify DER saturation in screening and feasibility reviews and in the results of impact studies for DER applications (Website for Hosting Capacity map for RI) Rhode Island System Data

Portal. Studies will be more complex and accommodating interconnections will likely require more involved infrastructure development, costs, and duration to construct.

7.
   a. The EPS substation bus voltage regulation, transformer capacity, and high voltage side protection may be impacted by large DER systems and the Company may specify interconnection to a higher voltage EPS, which allows for continued growth of small DER on the Company's Distribution EPS (e.g. residential solar).
   b. On single-phase radial distribution systems, generator interconnections with aggregate generator nameplate ratings over 50 kVA may require three-phase service and will be determined by the Company on a case-by-case basis.

8. The Company's distribution substations are subject to fault duty limitations. Adding generation to the Company Distribution EPS increases the amount of fault current imposed on the substations and equipment on the feeder(s). Exceeding the fault duties of equipment and devices at the substation(s) and on the feeder(s) as a result of DER facilities will not be permitted. Where the equipment fault duty ratings have been reached or exceeded, alternate methods of interconnection shall be explored or equipment shall be replaced at the expense of the Customer with comparable equipment of the appropriate withstand and/or AIC rating.
   8. Normally, one service is provided to the customer according to the Company's Electric Tariff, **RIPUC 2243**. However, under specified conditions, multiple service facilities may be supplied to the Customer from a Company Distribution EPS. The interconnection of multiple services shall be specified by the Company within the Company's operating practices and electric service requirements.[11]

6.2 Significant EPS Considerations

6.2.1 Direct Transfer Trip

IEEE 1547-2018 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. *An island is 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.* There are some cases where a DER's on-site equipment (such as voltage and frequency relaying or islanding detection) cannot reliably detect utility islands. Where the Company determines that a significant risk of islanding exists, direct transfer trip (DTT) may be required. DTT typically requires utility substation modifications to send a signal to trip the DER facility offline when the substation breaker opens. This also typically requires the Customer to lease a communication medium between the substation and the DER facility, as well as install a receiver and tripping device in their facility. DTT has inherent high costs and physical limitations associated with equipment installation due to the typical leased telecommunication line requirement at the EPS source and at the generator(s), as well as required utility substation modifications. The initial and recurring costs for DTT are at the expense of the Interconnecting Customer. See section 7.6.12 for more detail on when DTT may be required, which includes but is not limited to islanding

6.2.2 Transmission Ground Fault Detection

The addition of generation sources to distribution feeders can result in the backfeeding of the substation transformers, effectively turning a station designed for load into a generation step-up transformer. The Company's most common distribution substation transformer has a delta connection on the transmission side and a wye-grounded connection on the distribution side. Due to the transformer's configuration,12 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 rises significantly and rapidly. These overvoltages have the potential to exceed insulation levels of the station and transmission line equipment, and maximum continuous operating voltage of surge arresters. This situation can also leave transmission ground faults energized by the distribution-connected DER. Zero sequence voltage protection (commonly referred to as "3V0") on the primary side of the transformer is required in order to detect these overvoltage conditions. This 3V0 protection will disconnect the generation from the substation transformer, and stop the generation and transformer from contributing to the transmission-side overvoltage condition.

If the Company determines there is a likelihood of a zero sequence overvoltage event, transmission ground fault detection equipment and substation modifications may be required.

Illustration 6.2.2-1: Simple One Line for Transmission Ground Faults for Typical Substation Transformer Configuration

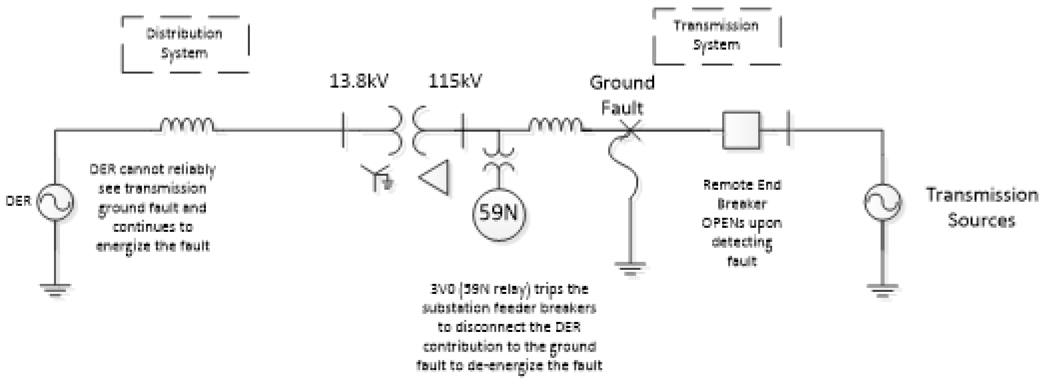


Illustration 6.2.2-1 shows an example transformer configuration for which it is difficult for distribution-connected DERs to detect and trip for transmission ground faults. Where the DER can contribute to this condition without tripping on the 88% undervoltage trip point, 3V0 may be required to be installed at the substation. Three voltage sensors (typically coupling capacitor voltage transformers (CCVT), are connected to the transmission side of the utility substation transformer. These voltage sensors are wired to a 59N relay ("3V0" or zero sequence overvoltage function), which trips the DER offline via utility breakers in the substation. This helps de-energize the ground fault from all sources. (Not all details or configurations are shown. Some substations may require protection for detecting transmission ground faults other than 3V0, such as scheme modifications, transformer replacement, or teleprotection systems). Customers should be aware that these modifications to the Company's substations require significant cost and time to install. The cost and time requirements are provided in the impact study according to the RI SCDG and the Company's Electric Tariff when performed for the Interconnecting Customer.

6.2.3 Secondary Metered; supplied from Non-Effectively Grounded EPS

DER interconnections to a Non-Effectively Grounded system shall require 59N ground-fault protection. This protection is accomplished by monitoring the primary voltage of the interconnection transformer with primary-rated PTs. For an existing secondary metered customer, especially for those within an urban unground-supplied area, this can present a significant change in service. Namely, conversion to a primary-metered service, to allow for the installation of the required, customer-owned PT's to the high side of the now-customer-owned interconnection transformer. This conversion may also trigger significant changes to the Company's equipment at the PCC.

7.0 General Design and Operating Requirements

From the perspective of interconnection, there are three main types of customer generation systems that interface to the Company's Distribution EPS. These include:

- Induction Generators
- Static Power Converters (inverter-based)
- Synchronous Generators

Each type has its own specific characteristics regarding synchronization equipment, protective functions, starting practices, and electrical operating behavior. There may also be additional specific requirements that may be identified as part of any impact study that is performed for a specific DER system and/or location as part of any Impact or Detailed Study that is performed for a specific location. For the purposes of this bulletin, any reference to DER ratings herein refers to the nameplate rating of the generation. Equipment nameplates shall meet ANSI standards.

1. For inverter based generation, this shall refer to the nameplate rating of the inverter(s). De-rating of inverter-based DER shall only be considered if the equipment is provided by the Customer's manufacturer with a permanent means of reducing the rated output, and so marked with an equipment nameplate stating the de-rated output.
2. For rotating machines, this shall refer to the nameplate rating of the generator (as opposed to the nameplate rating of the generator-set). De-rating of rotating machine generators by their prime mover capabilities shall not be permitted.
3. Equipment nameplates shall meet ANSI standards. De-rating of inverter based DER shall only be considered if the equipment is provided by the Customer's generator manufacturer with a permanent means of reducing the rated output, and provided with an equipment nameplate stating the de-rated output. De-rating of DER equipment shall be evaluated for acceptance on a case-by-case basis, with consideration given to specific project conditions, and will be accepted at the discretion of the Company.

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 the Company's requirements in this bulletin as well as to applicable codes and industry standards. Facility or campus-style microgrids may be permitted to automatically trip their PCC isolation device in order to island and serve the premises load; however, this device is required to be blocked from closing until authorized to do so by the Company. 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 through the RI SCDG process and is subject to witness testing and/or periodic testing as necessary. These situations will require that specific operating protocols to ensure that customer safety and the overall EPS safety and reliability are not in any way compromised.

7.1 General Criteria

The interconnection of all DER systems in parallel with the Company's EPS requires safeguards for synchronization and back feed situations in accordance with the **RI SCDG**. Each specific connection must be studied with respect to size, type, and the nature of the Company's Distribution EPS at the POI. Only the results of a specific study can indicate the suitability of a given generator connection to the Company's Distribution EPS and its possible economic viability. See the **RI SCDG** for detailed requirements.

7.1.1 Delivery Voltage

The Company will designate the type of service and delivery voltage based on the location of the Customer and the size and character of its proposed DER. Non-standard services will be required to be brought to standard, see ESB 750 Section 3.8 for reference.

7.1.2 Single Phase

Single phase DER system connections to the Company's EPS circuits under 600 volts present power quality and phase balance challenges. Single phase connections shall have these minimum characteristics:

1. Nameplate rating of a single generator or group of generators equal to or less than 50 kVA unless otherwise specified by the Company on a case-by-case basis.
2. Configured as a three-wire, line-to-line with neutral, or line-to-neutral with adequate load balance.
3. A dedicated service lateral with a dedicated transformer, when required by the Company.

7.1.3 Three Phase

Other than permissible single phase connections, three phase connections are required. The aggregated nameplate rating of all DER systems operating in parallel with the Company's EPS on the premise equal to or greater than 5 MW according to the RI SCDG for facilities, or group of facilities, have specific requirements under ISO-NE Operating Procedures No. 14 and No. 18. Refer to ESB 756 Appendix A for additional information in these cases and where wholesale DER connections are proposed.

7.1.4 Phase Balance and Voltage Tolerance

1. The Customer's DER facility shall permit equal current in each phase conductor at the service point or PCC. Voltage unbalance resulting from unbalanced currents shall not exceed 2% 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.
2. The interconnection of the DER facility shall not affect the Company's nominal voltage delivery at the PCC by greater than 3%.

7.1.5 Neutral Stabilization, Ground Faults, and Grounding

7.1.5.1 Multi-Grounded Distribution Area EPS:

1. An effectively grounded system with respect to the Company's EPS must be provided to ensure neutral stability, facilitate ground fault detection, and avoid distribution circuit over voltage during accidental isolation of the Company's area EPS from the Company's main system. This may require an additional ground source. see Section 7.3 for acceptable effective grounding options.
2. Contributing to ground faults on the Company's distribution EPS can desensitize the relays at the Company's substation. The effects of such grounding on the Company's ground-relay sensitivity shall be limited. The Company requires ground fault protection on any system that can be a generation source and to protect transformers that can be paralleled and supplied from two sources. When generator tripping is needed to sense ground faults on the Company's distribution EPS:

A. The winding arrangement of the Customer's DER facility transformer and the generator winding shall be such that the Company's system remains effectively grounded (see Section 7.3).
B. The Company may require that the grounding impedance be limited to the highest value suitable for neutral stabilization, or to limit generator ground fault contributions. Contribution to the faults on the Company's distribution EPS can desensitize the relays upstream of the Customer's interconnection. For that reason, it is required that the Customer provide a means to install a grounding reactor/resistor within their facility to limit the ground fault current. Where possible, this shall be limited to three times the generator rating and limit the rise of ground fault current at the point on the high voltage (primary) level nearest the proposed service point by no more than 10%. The grounding reactor/resistor shall not violate the effectively grounded system requirements. The impedance of the grounding reactor/resistor will be specified by the Company. If the 10% criterion is not met with the grounding impedance, other methods, upon Company acceptance may be required by the Customer to mitigate the increase in fault current.

3. Distribution circuits may have unbalanced loads (i.e. single phase loads) and triplen harmonics which result in neutral currents on equipment connected to multi-grounded circuits. Customers installing grounding equipment (i.e. grounding reactors, grounding transformers) are encouraged to consider this unbalance and triplen harmonics current when designing neutral-connected equipment where there is no transformer isolation from the Company's EPS. The Company recommends the Customer consider a minimum 100A continuous current rating (or the actual unbalance current, whichever is greater) for 15kV class-connected grounding reactors, and similar equipment parameters for other voltages.

7.1.5.2 Non-effectively grounded area EPS:

Where the Customer is permitted to interconnect through an un-grounded source, a 59N ($3V_0$) scheme may be required on the primary (utility) side of the accepted ungrounded source (ungrounded transformer serving the DER system, or generator as applicable) (see Figure 5) to detect utility-side ground faults. This may require the customer to become primary metered (See Section 6.2.3). Refer to Section 7.3.1 for further discussion on service transformer requirements.

It is the Customer's responsibility to detect and trip the facility for ground faults on the Company's distribution EPS – the Customer shall not rely on Company equipment for the protection of customer equipment (e.g. grounding transformers).

7.1.6 Reference Point of Applicability (RPA):

Unless otherwise specified by the Company, the performance and interoperability requirements within IEEE 1547-2018 shall be met at the RPA for the DER. This includes but is not limited to the default voltage and frequency ride through and control requirements. Except where otherwise specified, the RPA shall be the PCC for the DER. Specific DER configurations and EPS characteristics may require the need for additional Company review as to the RPA location and should be reviewed in accordance with Section 4.2 of IEEE 1547-2018.

7.1.6.1 DER Plant Control

Where individual DER units are used to form a DER facility, the requirements set forth in Section 7.6.1 and Section 7.8 shall apply to the DER facility. The combination of one or more DER Units may require the use of a facility Power Plant Controller (PPC) or similar device in order to meet the requirements of the latest version of IEEE 1547 and its amendments.

7.2 Service Equipment and Revenue Metering

7.2.1 Service Equipment Requirements

1. The Customer shall provide service entrance equipment as a part of their installation; see the Company's ESB 750. The Customer's service equipment shall be rated, at a minimum, for the maximum fault current available from the Company EPS and their own contribution from the generator(s), motors, etc.
2. Marking: The Customer shall install and maintain clearly marked permanent labels in accordance with the NEC, RIPUC 2258, and the Company's applicable ESB series requirements All Utility required marking shall be preprinted or engraved (no hand marking), have a minimum 5-year warranty for indoor or sheltered applications and have a minimum of 25-year warranty for use in outdoor applications. Labels shall be replaced when they no longer meet the legibility requirements of ANSI Z535.4. Labels shall be UL969 compliant. Materials used shall be weather resistant, UV stabilized and suitable for the environment where it is installed. Labels may be of engraved plastic, metallic foil, or polymer plastic mechanically or adhesive applied. For labels using adhesive, ultra-high strength bond adhesive shall be required. Data sheets shall be provided to indicate compliance with labeling requirements.

   Exception: Residential installations < 25kW with feed-through type meters may have labels with a minimum 5-year warranty regardless of location.

   In addition to NEC required marking, the following Utility requirements apply:

   A. The utility meter enclosure shall be labeled with the following:" WARNING: MULTIPLE POWER SOURCES" or "WARNING: DUAL POWER SOURCE" as applicable.
   B. The utility meter sockets shall be labeled as follows, [11] where applicable:
      a. Utility Service Meter
      b. Utility [DER type] Sub-Meter, where "DER Type" shall be designated by generation type as follows:
         i. "PV Generation" or other type Generation as required per Tariff, or
         ii. Storage.
   C. The Interconnecting Customer's AC utility disconnect switch shall be labeled "AC DISCONNECT".
   D. If the AC utility disconnect switch is not adjacent to the meter and/or PCC, the Interconnecting Customer shall provide marking as to the location of the switch.
   E. All Interconnecting Customer-Owned meters shall be labeled "CUSTOMER-OWNED METER"

[11] *Some installation may require multiple of the above meters depending on the incentive mechanism. Where multiple meters exist of the same DER type, each meter shall be labeled (i.e. Utility PV Generation Meter 1, Utility PV Generation Meter 2, etc…)*

3. For large Customers with aggregate generation equal to or greater than 500 kW, refer to the typical primary overhead service configuration requirements in **Exhibit 6.**
4. For situations where a higher voltage service connection is required, refer to the Company's ESB 751 as applicable.

7.2.2 Company Revenue Metering Requirements

1. The Company will specify the location and arrangement of all equipment required for the revenue metering of the Customer's service and DER facility as well as the monitoring of compliance with all applicable laws, regulations, interconnection agreements, and power purchase agreements. Reference the Company's ESB 750, Section 7 for additional information and requirements. The Company's net metering tariff, R.I.P.U.C. 2258, which describes qualifications for net energy metering. Where net metering does not apply, the Company's revenue metering will have multiple channels for power delivered and received for power purchase agreements (PPA) or be detented[12] to prevent reverse billing meter registration. When applicable, credit metering will be installed if arrangements have been made for energy sales to the Company.
2. The Customers may be required to provide a telecommunications line to each Company-owned revenue meter location. The telecommunication line would be required only in the event a cellular signal is not present for standard revenue meter reporting. The telephone line shall be capable of direct inward dial without human intervention or interference from other devices such as fax machines, etc. The Company will make the final determination of any Customer proposed alternate telecommunications service for Company-owned revenue metering, if any, for the specific Customer's DER system installation.
3. For fully rated meter installation, the DER source shall terminate to the lugs at the bottom of the meter socket. The Utility side connection shall terminate to the lugs at the top of the meter socket.

7.2.3 Company Revenue Metering Requirements (RI REGrowth Program)

RI REGrowth DER projects require a separate meter for DER metering such that two meters are normally installed including the supply meter at each location at the IC's expense. The service supply to the two meters can be one combined service connected to a multi-gang meter socket and then split for the final meter connections; see the Company's ESB 750 (https://rienergy.com/site/other-parties/business-partners/electric-specifications).

The installation of a single service from the weatherhead to a junction box mounted on the side of the house, which would subsequently serve individual meter sockets is not acceptable. Bifurcation of the service for the purposes of serving multiple meters related to RI REGrowth is only acceptable at the weatherhead. This metering shall comply with all sections of ESB 750 Section 7.0 as appropriate, along with these additional requirements:

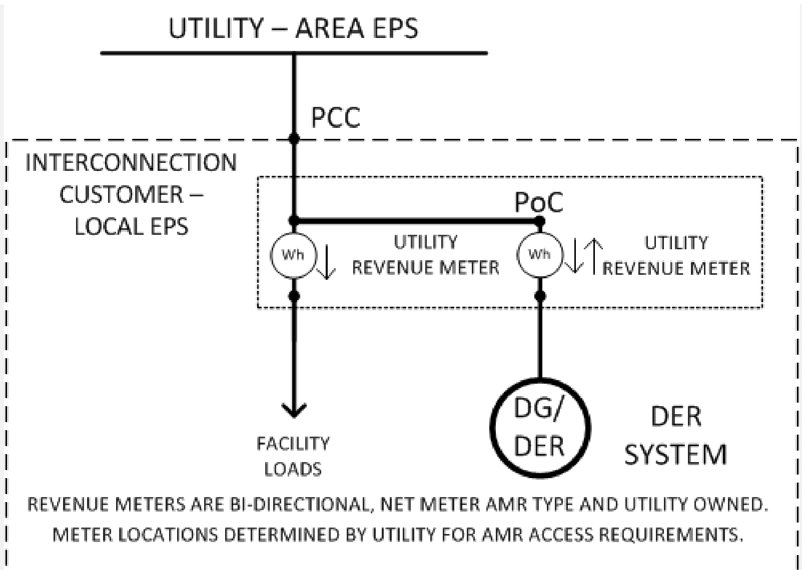
- ≤25kW, IC installs 2-gang meter socket trough at service location accessible for the Company's AMR meters (standard for load, net type for DG). For this type of installations, watthour type meters shall be used.
- >25kW, IC installs metering provisions at service location for the Company's wireless communications meters (detent for load, bi-directional for DG). For this type of installations, interval type meters with telemetry shall be used
- For 320A, and smaller, self contained meters:

[12] *"Detented metering" is measuring and registering power flow in a single direction by either mechanical, or electronic, or programming means in a revenue meter.*

  - 240V and less applications shall require a generator side disconnect. This can be one and the same as the Section 7.4 Manual Generator Disconnecting means.
  - 480V and network applications shall have an additional utility side disconnect.
  - All disconnects shall comply with Section 7.4
- For 400A and greater, transformer rated metering, there are no additional requirements.
- If Solar and ESS are to be installed together on a RI Regrowth project:
  - A bidirectional meter with no detent will be installed. The customer is required to implement a mechanism, such as an interlock or other approved method, to prevent the ESS from discharging through the re-growth meter.
- For Existing pad mounted service transformers:
  - Existing padmounted metering may need to be relocated to a parallel cabinet.
  - Number and size of secondary cable sets shall comply with ESB 759B Section13.0

Refer to illustration 7.2.3-1 for this meter location and installation.

Illustration 7.2.3-1 Typical RI REGrowth Metered Service



DER: Distributed Energy Resource
DG: Distributed Generator (a subset of DER)
EPS: Electric Power System
IC: Interconnection Customer
PCC: Point of Common Coupling
PoC: Point of Connection
Wh: Watthour Meter (may include demand quantities of Watts and VA)

7.3 Transformer

7.3.1 Secondary Served Customers

Where the Company provides secondary service, the Company's transformer is an equipment standard for service delivery voltages; see Section 3 in ESB 750. The maximum transformer size the Company will supply for a new secondary connected DER connection is under 300 kVA. Non-standard transformers will not be provided by the company. The Company will determine when dedicated services and a dedicated transformer are required in order to reduce the impact on other adjacent customers. The need for a dedicated transformer(s) may be determined at any point in the Customer's life cycle. If a dedicated transformer(s) is required, the Customer will be advised by the Company in writing. The cost of the transformer(s) will be the responsibility of the Customer according to R.I.P.U.C. 2243 and as permitted by the **RI SCDG**.

DER facilities proposed on the customer side of an existing Company-owned transformer may require the existing transformer service to be replaced under the following typical conditions, although not all inclusive:

1. DER exceeds the Company's transformer nameplate ratings. Transformer may be replaced up to a maximum of 300 kVA nameplate, which is the maximum standard sized transformer for this application.
2. DER up to a maximum of 999 kW, may be secondary metered on an appropriately sized existing transformer, replacement of existing transformer to a larger size up to 999 kW might be granted on a case by case basis but borne at the cost of the Interconnecting Customer.
3. Interconnection of DER to the customer side of the transformer creates undesirable effects on the company system.
4. Transformer is a non-standard design no longer provided by the Company's standard (see ESB 750 for standard service voltages) to meet the power quality, safety, and/or reliability to the individual Customer, or the EPS.
5. Existing transformer configuration is such that an additional primary side protection scheme is necessary for the DER facility to detect and trip the generation source for faults on the Company's EPS that would require the Customer to have primary service.

7.3.2 Primary and Higher Voltage Served Customers

The Company reserves the right to specify the winding connections for the Customer's 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 in the impact and detailed studies. Nameplates shall comply with ANSI C57.12.00 Section 5.12.

7.3.2.1 Effectively Grounded, Four-wire Multi-grounded 3-phase Wye EPS:

To avoid over voltage on the distribution EPS, the Company's policy requires that any DER facility 500 kW and above connected to a four wire distribution feeder to provide an effectively grounded system with respect to the Company's EPS. Refer to Section 7.1.4 for specific grounding requirements.

The Company requires that that the Customer select their interface transformer's winding configurations so that the DER system is interconnected effectively grounded. The Customer's DER facility shall be designed such that the DER cannot connect to the Company EPS without the means of effective grounding in service. In all instances, when the means of effective grounding is out of service or disconnected from the system, the DER site shall be disconnected from the Company EPS.

Aggregate DER below 500 kW in a Customer's facility may be permitted to utilize an ungrounded interconnection (e.g. primary delta[13] - secondary wye grounded or primary wye grounded – secondary wye grounded transformer with an ungrounded source). The Company reserves the right to require an effectively grounded source for generation 250

[13] For any transformer winding configuration with a Delta connection, a primary protection scheme is required.

kW and above depending on the DER saturation and other conditions on individual distribution EPS feeders.

Grounding transformer impedance shall be specified in ohms per phase, as stated in ANSI C57.32 Section 6.4.6. Grounding transformer nameplates shall comply with ANSI C57.32 Section 6.8.2

Effective grounding may be accomplished with the following configurations:

1. A wye-grounded to wye-grounded transformer with a grounded generator source. A neutral grounding reactor between generator neutral and ground may be required in event the generator's contribution to faults on the Company's EPS results in undesirable fault current values. See section 7.1.5.
2. A wye-grounded connected primary winding with a fully insulated neutral and a delta connected secondary winding (Note: primary protection scheme is required). The insulated neutral is to establish provisions for the addition of a grounding reactor or grounding resistor in the event the generator's contribution to faults on the Company's EPS results in undesirable fault current values. See section 7.1.5.
3. A wye-grounded to wye-grounded transformer with an associated grounding transformer.
4. A delta primary winding with a primary side grounding transformer and having any secondary configuration (Note: primary protection scheme is required).
5. A wye-grounded primary with wye-ungrounded secondary with a primary side grounding transformer.
6. A wye-ungrounded primary with wye-grounded or wye-ungrounded secondary with a primary side grounding transformer.
7. Effectively grounded will be allowed with a wye-grounded to wye-grounded transformer with 1741-SB inverters. A letter from both the inverters(s) manufacturer and Customer stating that the Reference Point of Applicability location meets all the IEEE 1547-2018 requirements must be submitted for review. Section 5.17 and UL1741 Section SB 4.3.5.17.1, which complies with IEEE 1547-2018 Section 7.4

7.3.2.2 Not Effectively Grounded, Three-wire 3-phase EPS:

On three-phase Company EPS circuits other than effectively grounded, only the connection of ungrounded primary interface transformers shall be permitted. A delta primary is normally required.

7.4 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. 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 de-activated, however the Company reserves the right to operate the DER facilities disconnect directly in emergency situations in accordance with Section 7 of R.I.P.U.C. 2258.

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 in accordance with Section 7 of R.I.P.U.C. 2258.

The disconnecting means shall have the following characteristics:

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 NEC and all applicable local, state, and federal codes.
2. Arrangement: The disconnect switch shall be installed to have the line connection (i.e., jaw side) of the switch connected to the utility source. Disconnects with more than one current carrying conductor shall be gang operated. It shall be capable of being grounded on the Company side. The grounding means must be compartmentalized such that the location where the ground is applied is completely barricaded from any live parts.

   For 320A and smaller self-contained meters, see ESB 750 for disconnect arrangements.
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 be a gang-operated, blade-type switch. Pull-out switches or blocks are not permitted for this application. 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. The visual open must be observable without opening the equipment.
   c. For DER systems connected directly to a Customer's building distribution system downstream of the PCC requiring a manual disconnecting means for isolation of the DER, the disconnecting means may be a draw out circuit breaker, disconnect, or comparable device mutually agreed upon by the Company and the Customer. 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. For installations above 600 V, the visual open of all three phases shall be capable of being observed without opening the equipment. Site-specific technical requirements will be considered by the Company if permitted to grant draw-out breakers with the provision for padlocking at the draw-out position, above 600 V or with a full load output of greater than 960 A, that are proposed to meet these isolation requirements. If the Company grants such use, the Customer will be required, upon the Company's request, to provide qualified operating personnel to open the draw-out circuit breaker and ensure isolation of the DER system, with such operation to be witnessed by the Company followed immediately by the Company locking the device to prevent re-energization. In an emergency or outage situation, where there is no access to the draw-out breaker or no qualified personnel, the Company may disconnect the electric service to the premise to isolate the DER system.
4. Location:
   1. The location of the disconnecting means shall comply with Company standards for working clearances, access road construction, vegetation management, and other similar requirement to ensure adequate access for Company personnel and equipment.
   2. The location of disconnecting means for all DER projects is subject to Company approval on a case-by-case basis, 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:

   a. 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.

   b. Should the disconnecting means be located behind the Customer's locked gate, double locking is required, where both the Company's and Customer's locks would be employed.

6. Identification: All required disconnecting means shall be identified by a permanent sign as required by the NEC and the ESB 750.

   Exception:

   In accordance with the **RI SCDG** and the Company's electric service requirements in ESB 750, inverter-based systems 25 kW and below are not required to have a separate manual disconnecting means if the unit has a disconnecting means integrated into the design and meets the requirements of the National Electrical Code (NEC).

   For systems 25 kW and below, a disconnecting or isolation means shall be required to be located between the Company meter and the DER device to allow for Company testing of the meter socket prior to meter installation. This device may be located based on customer preference, although where this device is not accessible to the Company, this may cause delay with associated meter installation and testing.

7.5 Generator Interrupting Device Requirements

7.5.1 General

1. For any aggregate generation connected to a common feeder that is 500 kW and greater, an interconnection interrupting device such as a circuit breaker shall be installed at the Customer's site. The 500 kW criteria are intended to encompass individual sites that are comprised of multiple smaller generators, totaling 500 kW or greater. It is also intended to encompass generation located at multiple sites that total 500 kW. Due to the unique circumstances of each individual installation, the Company reserves the right to require an interrupting device if necessary. As such, interrupting devices may be required for projects below 500 kW if the project warrants the installation. The Company may elect to waive this requirement if all Company protective and interrupting requirements are met by a Company device at the facility.
2. The generator interrupting device shall be designed to ensure the interrupting of the DER system, and its effective grounding source upon loss of interrupting device supply power, or upon loss of local power supply source.
3. When a local power supply source is utilized, generator interconnection interrupting devices shall have DC trip coils and tripping energy.
4. For primary wye grounded – secondary delta, and for primary delta interconnection transformers, the interrupting device shall be installed on the high voltage side. If there is more than one interrupting device, this requirement applies to each one individually. The interconnection interrupting device shall be capable of interrupting the current produced when the DER facility is connected out of phase with the Company's EPS.

5. The interrupting device shall be located upstream (closer to the Company's source) of the generation and any grounding transformer(s), so that it is capable of disconnecting the fault current contributions of the generation and grounding transformer.

7.5.2 Local Power Supply Requirements

When a continuous local power supply is proposed to comply with the Company's protection element operational requirements to safely remove the generation from the EPS the following conditions shall be met:

1. Failure of an uninterruptible power supply (UPS) rectifier shall not inhibit relay power supply and operation from the local power supply.
2. A fail-safe alarm contact shall be incorporated into the control trip scheme of the generator main interrupting device for loss of local power supply charge source.
3. The local power supply shall be sized to ensure successful operation of generator interrupting device upon loss of charge source. This supply shall be capable of providing all power requirements to initiate and complete the entire operating process of tripping the interconnection interrupting device.
4. The local power supply system shall be hard-wired and permanently installed. Portable cord-and-plug devices are prohibited.
5. System design calculations in accordance with IEEE standards and other industry standards as applicable shall be provided by the Customer for supply voltage, capacity specifications, and charging system provisions and are subject to the Company's review and acceptance.
6. Control circuits associated with protective relays shall be DC powered from a battery and battery charger system. The battery shall be the sole source of tripping energy. Solid state relays shall be self-powered, or DC powered from a battery and battery charger system.
7. If the DER facility uses a non-latching interconnection contactor, AC powered relaying may be permitted provided the relay as well as its method of application are fail-safe, meaning that if the relay fails or if the voltage and/or frequency of its AC power source deviate from the relay's design requirements for power, the relay or a separate fail-safe power monitoring relay will immediately trip the generator by opening the coil circuit of the interconnection contactor after a maximum 2 second time delay.

7.6 Protection and Protective Equipment Requirements

The Interconnection 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. The Interconnection Customer is also required to provide electrical equipment and relays with ranges and rating that will allow proper DER and premise relay system coordination with Company protection systems. Coordination margins and parameters will be determined by the Company.

The protection system shall be designed with interlocks and protective functions to ensure that there is proper voltage, frequency and phase angle conditions between the Company's EPS before the DER system is permitted to parallel. The Customer is responsible for voltage excursion detection and the detection of three-phase, line-to-line, and line-to-ground faults on the Company's EPS as well as faults on the Customer's system that cause overcurrent conditions on the Company's EPS.

All DER facilities shall meet performance requirements set forth by Section 4.2.3 in the RI SCDG. DER types of interconnection are categorized as either Group 1 "Facilities Qualified for Simplified Interconnection" or Group 2 "All Facilities Not Qualified for Simplified Interconnection" according to the **RI SCDG**. The Under Frequency relays for the Group 2 DER facilities shall not trip at frequencies higher than the curve provided for the "Eastern Interconnection Generator Tripping" in Figure 1 of the PRC-006-NPCC-1 Automatic Underfrequency Load Shedding criteria specified in the **RI SCDG**. The Company may specify values within the allowable ranges of IEEE 1547-2018 subject to the limitations on voltage and frequency trip settings specified by the regional reliability coordinator that consider bulk power system impacts of affected aggregate DER capacity. Where Regional ISO voltage and frequency requirements apply, the Customer shall refer for specific requirements related to North American Electric Reliability Corporation (NERC) Protection and Control (PRC) standards.[14]

The Customer's interconnection system shall have the capability to withstand voltage and current surges in accordance with the environments defined in the latest IEEE Standard C62.41.2 or IEEE Standard C37.90.1 as applicable.

For the purpose of evaluating fault current, short circuit protection, and protective relay settings, current values are based on the full Volt-Ampere (VA) nameplate rating of the equipment, which may be greater than the kW rating of the equipment. For ESS, all protection reviews, regardless of any on-site operational limitations, are performed at the sum of the nameplate ratings of the ESS and any paired DG since fault currents are related to the full kVA nameplate ratings of the inverter(s) and/or generators used.

7.6.1 Type Tested (Certified) Equipment

Protective equipment that has been type tested and recognized under UL Standard 1741 by the RI SCDG for Group 1 DER facilities will be permitted. The Customer shall follow the testing requirements as outlined in the RI SCDG. Exhibit 7 attached is a guide for the Company's witness for verifying a type tested net-metered DER installation's operational compliance.

7.6.2 Non-Type tested Equipment

Protective equipment that has not been type tested per the RI SCDG and considered as Group 2 DER facilities will be permitted with the implementation of utility grade protective devices acceptable to the Company. The use of utility grade relays[15] and relay redundancy is acceptable subject to prior Company review and acceptance per section 7.6.3.2.

7.6.3 Number of Relays Required

For all DER facilities equal to or above 500 kW, and those that require supplemental ground sources (Section 7.1.5), redundant relaying is required for the detection of Area EPS faults. Relays are considered redundant only when two utility grade relays with identical protective functions are provided.

Where relay performance may affect the operation of the Company's Distribution EPS at service voltages less than 15kV, a single utility grade microprocessor-based relay along with a Company approved scheme, where relay failure automatically trips the associated breaker(s), may be acceptable. If the Customer decides not to use redundant protection systems on their other equipment, then appropriate action such as removing equipment from service shall be taken when a piece of equipment is no longer adequately protected. The utility grade relay failure alarm shall be wired to trip and block close the Company-designated generator interrupting device. Auxiliary relays, where used, shall be fail safe and utility grade. If two utility grade relays are used to provide redundancy, whether relay failure, or being out of service, if neither relay can perform the intended protection functions the protection scheme shall trip and block close the interrupting device.

[14] *See* *https://www.nerc.com/pa/Stand/Pages/ReliabilityStandards.aspx* *and* https://www.nerc.com/pa/Stand/Pages/USRelStand.aspx

[15] *See definition of "utility grade" for protective device equipment in Section 4.*

7.6.3.1 Certified Inverter-based Energy Resource Protection Requirements

IEEE 1547-2018 compliant and UL-1741 certified[16] inverters shall be equipped with an internal active anti-islanding scheme, under voltage (27), over voltage (59), under frequency (81U) and over frequency (81O) relays. Inverter based generators shall be in compliance with the latest version of IEEE 1547-2018. The Customer shall provide the voltage and frequency ride through capabilities as specified in the associated 1741-SB Definition (see Section 4.0 - Definitions) in any inverters installed as part of a DER facility proposed to interconnect to the Company's EPS. The voltage regulation capabilities shall be turned OFF unless otherwise required by the Company. See section 7.8 for further inverter function requirements.

7.6.3.1.1 Certified Inverter-based Energy Resources below 500 kW

If the inverter(s) are IEEE 1547-2018 compliant and UL-1741-SB listed in the configuration proposed for interconnection, the internal relays are considered as the only required protection and an additional utility grade relay is not required to be installed. At the Company's sole discretion, the Company reserves the right to require a utility grade relay for certified systems above 250 kW with, at minimum, functions 27, 59, 81U/O enabled when a rotating engine or wind generation is involved.

7.6.3.1.2 Certified Inverter-based Energy Resource 500 kW or greater

For inverters that are IEEE 1547-2018 compliant, and UL-1741-SB listed in the configuration proposed for interconnection, inverter internal relay functions are considered as primary protection. The Company requires one additional utility grade relay to be installed as secondary to the utility grade protection for inverter-based DER equal or greater than 500 kW. The 27, 59, 81U/O, and 51N or 51G elements shall be activated in the utility grade protection relay. The Customer shall provide either 51G ground time overcurrent or 51N residual neutral time overcurrent as part of their ground protection requirements when meeting the NEC. On circuits where generation is permitted to connect as an ungrounded source, a 59N relay function is required to detect ground faults on the utility. Where Company-required functions are not redundant, such as overcurrent or 59N functions, refer to section 7.6.3 for fail-safe tripping requirements.

7.6.3.2 Non-Certified Energy Resource Protection Requirements

Where Company-required functions are not redundant, such as overcurrent or 59N functions, refer to section 7.6.3 for fail-safe tripping requirements.

7.6.3.2.1 Energy Resources below 500 kW

For any non-certified generator less than 500 kW one utility grade relay is required to be installed. 27, 59, and 81 U/O at minimum shall be active in the utility grade relay. For all systems 250 kW or larger, the Company reserves the right to require redundant utility grade relay(s) when a rotating engine is involved.

7.6.3.2.2 Energy Resources 500 kW and greater

For any non-certified generator equal or above 500 kW, two utility grade relays are required to be installed with. 27, 59, 81 U/O, and overcurrent elements for both phase and ground. On circuits where generation is permitted to connect as an ungrounded source, a 59N relay function is required to detect ground faults on the area EPS.

[16] *See definition for "certified" in Section 4.*

7.6.4 Instrument Transformers for Protective Relays

7.6.4.1 Current Transformers (CT)

CT ratios and accuracy classes shall be chosen such that secondary current is less than 5 amperes normal operation, 100 amperes under maximum fault condition and transformation errors are consistent with Company practices. For the primary wye grounded – secondary delta installations, the CTs shall be installed on the high side. If the interconnection transformer is primary wye grounded – secondary wye grounded, the CTs can be installed on either high or low side, provided the CTs sense the current contribution to Company EPS faults from ground sources installed on the facility. CT accuracy and burden calculations shall be provided for review by the Company. Metering class CTs shall not be used for fault current sensing for overcurrent protection but may be used for site limiting 32 element input.

7.6.4.2 Voltage Transformers (VT) and Connections

Voltage sensing is required on all three phases on the utility side of the interrupting device. VTs for voltage sensing shall be configured wye-grounded (Yg-Yg). Voltage measurements shall have no more than 2% error under the expected ambient temperature range (-10°C (14°F) to +45°C (113°F)) and no higher than 4% error under all operating temperatures (-40°C (-40°F) to +65°C (149°F)). If the secondary voltages can be used to detect voltage depressions for faults that occur on the Utility EPS, and the secondary voltage is within the relay's acceptable operating range, VTs may not be required. The use of Yg-Broken Delta VTs will be considered by the Company on a case-by-case basis. VTs used for 59N protection shall be rated for full L-L primary voltage. Note: LEA capacitive voltage sensors are not allowed to be used on non-effectively grounded circuits.

7.6.5 Protective Relay and Trip Circuit Hard-Wire Requirements

Unless authorized otherwise by the Company, protective relays shall be hardwired to the device they are tripping. Further, interposing computer-based or programmable logic controllers, auxiliary modules, or the like are not permitted in the trip control scheme between the relay and the device being tripped. Trip circuits shall not be fused.

The use of interposing relays is subject to approval by the Company. Interposing relays, if proposed, shall be utility grade, and the tripping scheme shall be fail-safe.

Meter selector switches shall not be connected into the secondary circuits of current transformers used with protective relays specified by the Company.

Generator protective relays shall be located no greater than 30 feet from the device in which they control.

7.6.6 Protective Relay Test Switch Requirements

Microprocessor and non-draw out relays, including relay function 86 shall have ABB FT-1, or equivalent, test switches isolating all inputs and outputs of the relay. All test switches shall be labeled for the associated relay functions.

- <u>AC Inputs</u>: Each relay shall have its own AC test switch. DC inputs or outputs are not permitted on AC test switches.
- <u>DC Inputs and Outputs</u>:
  - For relays designated by the Company as necessary to protect the Company's Distribution EPS, it is required that each individual relay have its own DC test switch that isolates the positive and negative DC for each input and output.
  - For relays required to protect the Customer's equipment, it is required that each relay have its own DC test switch for inputs and outputs. For ease of

maintenance testing and troubleshooting, it is required to isolate the positive and negative DC of the input and output.

- Groups of relays that protect the same piece of equipment, such as a transformer or a feeder, may share a DC test switch under the following conditions:
  - The individual blades of the test switch shall be grouped by relay.
  - A permanent label shall be affixed to the relay panel identifying the use of each blade.

  Exception: *Where the relay inputs are supplied by a control cable (such as a some recloser installations) and the relay test set uses a control cable that inputs to the same port in the recloser control enclosure, test switches may not be required.*

7.6.7 Voltage Relay Devices

Voltage relays shall be frequency compensated to provide a uniform response in the range of 40 to 70 Hz. and meet IEEE 1547-2018 requirements including capability for under/over voltage ride through. See Table 7.6.11.1-1 below for default voltage relay settings.

7.6.8 Frequency Relay Devices

Over and Under Frequency relays shall meet IEEE 1547-2018 requirements including capability for under frequency ride through. See Table 7.6.11.1-1 below for default frequency relay settings.

7.6.9 Synchronizing Devices

The Customer shall designate one or more synchronizing devices that employ a synchronizing protection element (25) such as motorized breakers, contactor/breaker combinations, or a fused contactor (if mutually agreeable) to be used to connect the DER facility's generator to the Company's EPS. This synchronizing device could be a device other than the interconnection interrupting device and shall be utility grade. The synchronizing device shall be capable of interrupting the current produced when the DER facility is connected out of phase with the Company's EPS. Synchronism check relay functions are required at all breakers through which the generation will be synchronized with the utility source. This includes any breakers where any part of the Customer's DER facility will island and then synchronize back to the Company's EPS.

7.6.10 Overcurrent Relays

Overcurrent protection is required to detect faults on the Company's EPS, as well as faults on the Customer system that cause overcurrent conditions on the Company EPS. Overcurrent elements are required for both phase and ground in accordance with 7.6.3. Where a voltage-controlled phase element (51) is utilized, the relay shall utilize voltage sensing via the Yg-Yg VTs specified in section 7.6.4.2

7.6.11 Utility Grade Relay and Protective Device Settings and Verification

7.6.11.1 Default Voltage and Frequency Set points for Inverter-Based Energy Resources

Unless otherwise specified by the Company, the default settings for voltage and frequency trip elements are required to have setting ranges according to the following table 7.6.11.1-1 and the final time delay settings shall be approved by the Company:

Table 7.6.11.1-1 Utility Grade Relay and UL 1741 SB Certified Inverter Default Voltage & Frequency Set Points

DEVICE	PICKUP RANGE (Defaults set points in bold)	DEFAULT CLEARING TIME (sec)
Under Frequency (81U)	≤ **56.5 Hz**	**0.16**
Under Frequency (81U)	< **58.5 Hz**	**300**
Over Frequency (81O)	**61.2 Hz** ≤ f <62.0Hz	**300**
Over Frequency (81O)	≥ **62.0 Hz**	**0.16**
Under Voltage (27)	≤ **50%** of Nominal	**1.1**
Under Voltage (27)	50% <V≤ **88%** of Nominal	**3**
Over Voltage (59)	**110%** ≤V< 120% of Nominal	**2**
Over Voltage (59)	≥ **120%** of Nominal	**0.16**

DER mode of operation during different voltage and frequency ride through levels must follow the ride through requirements for 1741-SB inverters as defined in Section 4.0 - Definitions.

Settings other than the default, within the settings ranges in IEEE 1547-2018, may be acceptable on a case-by-case basis and are subject to review and approval by the Company. DER facilities with Direct Transfer Trip installed may be required to have wider than the default settings to comply with ride through requirements.

Note that consistent with IEEE 1547-2018, the pickups are exact set points and the time delays are maximum total clearing times (including relay and device interruption time).

Unless otherwise specified by the Company, the ride through and default trip elements settings for voltage angle phase jump and ROCOF are required to follow IEEE1547-2018 and according to the following table 7.6.11.1-3:

Table 7.6.11.1-3 UL 1741 SB Certified Inverter ROCOF and Voltage Angle Phase Jump

DEVICE	Ride Through Requirement	PICKUP RANGE
ROCOF (if enabled)	IEEE1547-2018 Section 6.5.2.5 Cat (III)	**> 3 Hz/sec**
Phase Jump (if enabled)	IEEE1547-2018 Section 6.5.2.6	**-**

7.6.11.2 Default Voltage and Frequency Set points for non-Certified Inverter & non-Inverter based Energy Resources

Unless otherwise specified by the Company, the default settings for voltage and frequency trip elements are required to have setting ranges according to the following table 7.6.11.2-1 and the final time delay settings shall be approved by the Company:

Table 7.6.11.2-1 Utility Grade Relay and non-certified inverter & non-Inverter based Generation Default Voltage & Frequency Set Points

DEVICE	PICKUP RANGE (Defaults set points in bold)	DEFAULT CLEARING TIME (sec)
Under Frequency (81U)	≤ **56.5 Hz**	**0.16**
Under Frequency (81U)	< 58.5 **Hz**	**300**
Over Frequency (81O)	**61.2 Hz** ≤ f <62.0Hz	**300**
Over Frequency (81O)	≥ **62.0 Hz**	**0.16**
Under Voltage (27)	≤ **50%** of Nominal	**0.16**
Under Voltage (27)	50% <V≤ **88%** of Nominal	**2**
Over Voltage (59)	**110%** ≤V< 120% of Nominal	**2**
Over Voltage (59)	≥ **120%** of Nominal	**0.16**

Settings other than the default, within the settings ranges in IEEE 1547-2018, may be acceptable on a case-by-case basis and are subject to review and approval by the Company. DER facilities with Direct Transfer Trip installed may be required to have wider than the default settings to comply with ride through requirements.

Note that consistent with IEEE 1547-2018, the pickups are exact set points and the time delays are maximum total clearing times (including relay and device interruption time).

The above default voltage and frequency trip settings are consistent with the “”Default IEEE 1547-2018 Settings Requirements”, dated May 9, 2022, Section 3.0 - Settings for non-inverter based DER.

7.6.11.3 Synchronism Check Setting Requirements for all types of Generation

Unless otherwise specified by the Company, the default settings for utility-grade synchronism check elements are required to have settings according to the following table 7.6.11.2-1 and the final settings shall be approved by the Company:

Table 7.6.11.2-1 Relay Settings to Parallel with the Company EPS

Generator Size (kVA)	Max. Frequency Difference (□ f, Hz)	Max. Voltage Difference (□ V, %)	Max. Phase Angle Difference (□ □, degrees)
0-500	0.3	10	20
>500 – 1,500	0.2	5	15
>1,500 – 10,000	0.1	3	10

7.6.11.4 Company-designated Relays and Customer Settings

1. The Company will review the Customer’s settings and their calibration and test results of those relays that the Company designates as being required to satisfy the Company protection practices. In addition, the Company may require the relaying summary and logic diagrams depending on the complexity of the installation.
2. Any relay setting specified by the Company shall not be changed or modified at any time without the written consent of the Company.
3. The Customer shall be responsible to specify the settings, calibrate, test, and maintain the balance of their equipment.

7.6.11.5 Company Verification of Relay Testing

Prior to the Witness Test, the Company requires a letter from the Customer stipulating that all Company–designated protective devices have:

A. control wiring verified against the accepted design drawings, and

B. the calibration test performed satisfactorily according to the relay setting document of the accepted design.

7.6.12 Unintentional Islanding Protection for DER

The Customer's DER system shall not energize a de-energized Company circuit; therefore, anti-islanding protection is required for parallel generation on the Company's distribution EPS. If the Company determines that an anti-islanding protection scheme is required to mitigate the risk of a formation of an island in addition to the generator facility's own islanding detection scheme, then the Company will require direct transfer trip (DTT). The Customer may propose alternative methods of anti-islanding protection of their own generation facility, although it is the Customer's responsibility to demonstrate comprehensively the validity of such methods, and the Company reserves the right to make the final determination as to which anti-islanding protection method is suitable to meet the EPS safety and reliability requirements.

Note: A Customer wishing to use a generation system as a stand-by or emergency generator shall submit details regarding an interlocking scheme, or transfer switch to prevent the energization of a de-energized Company circuit that complies with Rhode Island Energy ESB 750, Section 11.

7.6.12.1 General

1. 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.
2. During DER impact evaluation, when a DER on the circuit causes the Company's system protection to be unable to trip for end of line faults, appropriate measures will be taken to correct this protection gap. The Company's device setting adjustments, additional protection devices, and/or customer impedance grounding may be required.
3. The requirements outlined below in regards to unintentional islanding mitigation risks are not applicable for DER proposed to be interconnected to a Company secondary network system. The Company's network systems are not designed for and cannot accept back feed.
4. Utility interactive inverters evaluated under these requirements shall not actively regulate frequency and/or voltage or provide Var support functions. Any inverter type generation established as frequency and/or voltage regulating or Var supportive will be reviewed under section 7.6.12.5 Certified inverters with advance functions requirements.
5. DER threshold values shall be analyzed in aggregate where multiple DER projects are supplied from a single point of connection to the EPS. Individual DER projects on sub-divided or adjacent parcels may be evaluated based upon total aggregate nameplate ratings as an equivalent single point connection to the EPS.
6. For cases where the line section aggregated DER is ≤ 33% of minimum load regardless of DER type mix and is connected to < 35 kV distribution EPS no additional requirements identified below shall be required.
7. For DER equipped with DTT, those DER facilities will not be factored into the 10 and 25% ratio screens identified in this bulletin.
8. Where used within this document, reclose blocking is a voltage supervised reclose permissive feature required at any mid-line automated interrupting device identified through the steps outlined. Where this feature is required, each mid-line device is also

required to be SCADA equipped through Rhode Island Energy's distribution EMS cellular network.

9. 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.
10. Each screen shall be 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.

7.6.12.2 Islanding risk mitigation methods required

Special conditions outlined within this section are required at minimum, regardless of the screening outcomes applicable in the following sections.

1. Cases where the Company's PCC recloser is required regardless of DER type:
   a. DER ≥ 300 kW and DER > 33% minimum load and is connected to < 5 kV EPS.
   b. DER> 500 kW and connected to > 15 kV and < 35 kV EPS where DER > 50% onsite minimum host load.
2. Cases where additional EPS protection schemes, including but not limited to transfer tripping, may be required regardless of DER type:[17]
   a. If line faults (phase and ground where applicable) cannot be cleared by DER protective device or the Company's PCC recloser.[18]
   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.
3. The Company shall be provided with access rights, whether easement or fee-owned right-of-way, of the Company's facilities on the Customer's property for the PCC recloser installation serving their DER facility. See Exhibit 6 for a typical one-line configuration of a PCC recloser primary metered overhead service.

7.6.12.3 1741-SB Certified DER [19]

1. If 33% or higher of UL1741-SB certified inverters on the feeder (on aggregate rating basis) have anti-islanding detection method belonging to Group 1 and/or Group 2A[20], then the screens 2, 3.b, 3.c and 4 apply. Otherwise:

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

[18] *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).*

[19] *Inverter firmware derating is not acceptable for reduction of system size to satisfy thresholds within this section.*

[20] *As defined in SANDIA technical report* https://www.osti.gov/servlets/purl/1463446 *: Group 1: Methods in this group produce an output perturbation in positive-sequence fundamental frequency (or phase) specifically for island detection. This perturbation increases as the error increases (e.g. positive feedback on frequency error). It may be continuous or pulsed. Group 1 inverters use this positive feedback to promote instability after an island forms. Within the normal frequency operating range, feedback is key to destabilizing. Feedback continues until a frequency trip limit is reached and includes no dead zone.*

a. For DER>= 500 kW:
   i. ROI study is required and requirements in screen 4 apply.
b. For DER < 500 kW:
   i. Screens 2 and 3 and 4 apply.

2. Proposed DER rated ≤ 250 kW
   a. No Requirements
3. Proposed DER rated > 250 kW and < 500 kW
   a. If lower than 33% of UL1741-SB and existing SA certified inverters on the feeder (on aggregate rating basis) have anti-islanding detection method belong to Group 1 and/or Group 2A, then recloser blocking is required on the next upstream device sectionalizing device.
   b. Line section aggregated non-certified DER is ≤ 10% of mix.
      i. No additional requirements.
   c. Line section aggregated non-certified DER is > 10%
      i. Company owned PCC recloser and reclose blocking required on the next line segment upstream sectionalizing device.
         - Company PCC recloser may be waived if: ROI study show no risk of islanding or aggregate DER on line section < 500 kW or DER to load ratio of line segment is <25%
4. Proposed DER rated DER ≥ 500 kW
   a. Company owned PCC Recloser required.
   b. Reclose blocking required on the next upstream sectionalizing device if line segment aggregate DER > 50% of minimum load.

7.6.12.4 Non-certified inverters, induction & synchronous machines

1. Require ANSI C37.90 utility-grade protective relay with IEEE 1547-2018 voltage and frequency tripping and restoration functions.
2. Total aggregate line section DER > 33% minimum load
   a. DTT required.
3. DTT may be waived if Risk of Island study demonstrates Run on Times less than 2 seconds.
   a. Reclose blocking required on the next upstream sectionalizing device.

7.6.12.5 Certified inverters with advance functions

1. Require ANSI C37.90 utility-grade protective relay with IEEE 1547-2018 voltage and frequency tripping and restoration functions.
2. Total aggregate line section DER > 33% minimum load
   a. Detailed Risk of Islanding study is required.

Group 2A: Similar to Group 1 in that the method produces an output perturbation in positive-sequence fundamental frequency (or phase) and the perturbation increases with error (i.e., positive feedback on frequency error). The difference is that positive feedback, within trip bands, is not continuous. Inverters in this Group may have a stepped or otherwise discontinuous response as the magnitude of perturbation reaches a limit prior to the frequency trip thresholds. Inverters with a dead zone around 60-Hz are excluded from Group 2A.

Exception: This requirement does not apply to certified inverters with frequency-watt enabled.

7.6.13 Import/Export Control

The customer's facility may be designed to limit export and/or import at the PCC or the PoC. Facilities that qualify for the Simplified Application process and have an aggregate nameplate rating less than or equal to 25 kW may utilize a UL 1741-Power Control System (PCS) CRD certified Power Control System, with an Open Loop Response Time of 2.0 seconds or less. A UL 1741-PCS certification letter, complying with the latest edition of the CRD, shall be supplied with the application and as part of the certification on the Commissioning memo.
Non-Simplified applications will be required to utilize a power limiting scheme (e.g. 32 element) with utility grade controls. PT, CT, and relay % error will be factored into the final setpoint of the 32 elements during the SIS. Stacking of manufacturer published accuracy will be used in the calculation to account for both manufacturing defects, lifetime wear, and replacement.

7.6.13.1 De-Rated Inverters

Where the customer chooses to factory de-rate inverters to 90% of nameplate or less and the total aggregate nameplate is greater than 500 kVA, a 32 element will be required to prevent unintended full nameplate export. This can be accomplished with two options:

1. The customer can install a power element in their equipment with the accuracy risk shared between the customer and the company, and the company will witness test this equipment at the nameplate derated figure.

2. The company can install a power element in the PCC recloser with accuracy risk shared between the customer and the company. The current and voltage sensing for the company recloser is designed for relay class accuracy. For a 5,000 kVA site this may require a reduction in site export by as much as 7.5%

7.6.13.2 Minimum Import

Minimum import may be proposed on a case-by-case basis to avoid system modifications that are the result of thermal EPS analysis. These systems will require a 32 element in a utility grade relay, located at the PCC.

7.6.13.3 Time Variant Nameplate Curtailment

Customer facilities that are proposed to have time variant import/export schedules shall utilize an automation controller that complies with IEEE 1613 and IEEE C37.90.

7.6.14 Intentional Islanding Protection for DER

Normally, the Customer's DER system shall not energize a de-energized Company circuit. Where a customer DER system is interconnected to the Company EPS and can also operate in intentional islanding mode, the DER system shall not cause inadvertent back feed when the Company EPS is de-energized while operating in or transitioning to islanding mode.
Note: A customer wishing to use a generation system as a stand-by or emergency generator (not normally in parallel) shall comply with ESB 750 Section 11.

7.6.14.1 Certified Inverter Based Resource Paired with Microgrid Interconnection Devices (MID)

The inverter/MID combination shall be certified with the latest version of UL 741 CRD for Multimode Operation. The IC shall submit a certification document signed and dated by their NRTL to the Company for acceptance. The IC shall also submit the Sequence of Operations for transition to and from parallel operation with the Company EPS; and the adjustments to DER settings, as described in IEEE 1547-2018 Section 8.2.7. The Islanding Detection Method shall be enabled within 30 cycles or less, of the paralleling of the MID. IEEE 1547-2018 and UL 1741 SB compliant inverters certified UL 1741 CRD for Multimode may be considered as the only protection required for DER systems transitioning between Utility Interactive Mode and Standalone Mode. At the Company's sole discretion, the Company reserves the right to require additional protection against inadvertent backfeed of the area EPS.

7.7 Visibility and Control (V&C) at DER Facility

DER ranging from 75 kW in capacity and up on radial distribution systems may require supervisory control and data acquisition (SCADA) communication for visibility to the Company's energy management system (ADMS) and to incorporate the ability for the Company's system operators via ADMS to remote trip the generation, or DER facility, from the Company's EPS. This visibility is essential in maintaining daily system operability and the flexibility to transfer loads and feeder segments to allow for system upgrades, repairs, seasonal loading transfers, and other normal distribution system management functions that may require a SCADA remote terminal unit (RTU) or a PCC Recloser at a DER facility.

7.7.1 For Independent Power Producer (IPP) – "Utility Connected Stand Alone" projects (DER with no load)

1. The Company generally does not require any RTU system for IPP generators, regardless of the size or voltage class.
2. For all standalone DER >= 500 kW in facility size, a Company-owned PCC recloser is required for visibility & control.
3. Where available, the Company will utilize the Company-owned PCC recloser serving the DER installation to obtain Company's operational polling data.
4. The Interconnecting Customer (IC) is advised to communicate with Independent System Operator (ISO) -New England for any telemetry requirement as ISO-NE may require real-time monitoring between ISO-NE ADMS and the DER site. The IC shall refer to the ISO-NE website and ISO-NE customer service help desk for details.
5. The Company reserves the right to require the IPP customer to install an RTU at their facility for any special circumstances. One situation where an ADMS-RTU may be required is where there is Distribution EPS feeder selectivity operation.

7.7.2 For Non IPP - "Behind the meter" projects (DERs with customer Load)

1. For Non IPP projects, the Company will require the Interconnecting Customer (IC) to install RTU at their facility based on the Company's delivery voltage level and the DER size. RTUs will be required for "behind the meter" DER installations for the feeder voltage class values provided in the table below.

Table 7.7.2-1: RTU Requirements by Facility Size

Delivery Voltage Class	Non IPP Generating Capacity	Non IPP ESS Capacity

5kV or below.	150 kW or greater	75 kW or greater
greater than 5kV but less than 15kV	500 kW or greater	250 kW or greater
>15kV	1.0 MW or greater	500 kW or greater

2. ADMS-RTU installations may be required for DER applications not covered by the conditions above as determined by the Company on a case-by-case basis. One situation where an ADMS-RTU may be required is where there is Distribution EPS feeder selectivity operation.

3. The control portion would only involve the remote trip and block closing of the Customer's interrupting device(s) designated by the Company. The block close function will be performed by control circuitry and is subject to review by the Company for acceptance.

4. The required inputs from the RTU to the Company's ADMS shall be as follows:
   - 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
   - Three phase line current for each generator
   - Three phase line current at the PCC with the Company (when there is multiple generator breakers)
   - Three phase line-to-line voltage for each generator
   - Three phase line-to-line voltage at the PCC with the Company (when there is multiple generator breakers)
   - Output kW for each unit (+ delivered to the Company, - received)
   - Output kVAR for each unit (+ delivered to the Company, - received)
   - Total MW (+ delivered by generator, - received by generator) at the PCC
   - Total MVAR (+ delivered by generator, - received by generator) at the PCC

   Exceptions to the above list may be considered by the Company on a case-by-case basis.

   Note:The Company will provide an ADMS-RTU point list for inputs required at the DER system.

5. When a Company ADMS-RTU is specified for a parallel generation project, the Company will determine the requirements for equipment, installation, and communications media in the interconnection study for the DER system. The Customer will be responsible for all initial and recurring costs associated with communications for their RTU.

6. The Interconnecting Customer (IC) is advised to communicate with Independent System Operator (ISO) -New England for any telemetry requirement as ISO-NE may require real-time monitoring between ISO-NE EMS and the DER site. The IC shall refer to the ISO-NE website and ISO-NE customer service help desk for details. . If the IC has determined the Company shall be the backup RTU, the IC shall supply an IPP Scada Design Worksheet, a Points Assigned List and an overall construction one line showing how the RTU will be integrated with the Company's ADMS system. The IC shall supply preliminary information during the impact study phase to enable timely update of the Company's ADMS screens and purchase of equipment. Final information shall be provided 120 days before ATI. The Company will not be liable if the IC cannot connect their back up RTU for ISO purposes due to delays in providing the connection architecture, points list and simple one line diagram in a timely manner.

7.8 Voltage and Frequency Ride Through and Control Requirements

7.8.1 Voltage and Frequency Ride Through

Inverter-based DER shall meet the requirements of 1741-SB Definitions, as defined in Section 4.0. See section 7.6.11 for corresponding voltage and frequency default trip settings.

7.8.2 1741-SB Voltage and Frequency Control

1. All generators shall be in compliance with the latest revision of IEEE 1547-2018. Field adjustable settings shall not be changed without express written consent of the Company.
2. The voltage and frequency capabilities permitted in IEEE 1547-2018 shall be disabled by default in accordance with Table 7.8.3.2-1 unless otherwise approved by the Company.

Table 7.8.3.2-1: Default Mode Settings for 1741-SB Certified Inverters

Function	Default Activation State
SPF, Specified Power Factor	OFF[21]
Q(V), Volt-Var Function with Watt or Var Priority	OFF
DER (except Energy Storage) normal ramp rate	Default: 100% of DER nameplate
Energy Storage Charging/Discharging Ramp Rate	ON Default value: 2.0[22] % of maximum current output per second‡
FW, Freq-Watt Function	ON[23] Certified inverter shall comply with 1741-SB Definition. See Table 7.8.3.2-2 for settings. For Non-Certified DER see Table 7.8.3.2-3
Rate of Change of Frequency (ROCOF)	Not mandatory. Refer to Table 7.6.11.1-3 for Ride through and settings and ride through requirement
Voltage Angle Phase Jump	See Default IEE 1547-2018 Setting Requirements

‡ *Higher ramp rate to the default settings proposed by Customer may be considered to be evaluated during System Impact Study.*

Table 7.8.3.2-2: Default Frequency-watt Settings for DER UL1741SB Certified Inverters

Required Default Settings		Comparison to IEEE Std. 1547-2018 Default Settings for Category III	
Parameter	**Settings**	**Settings**	**Within ranges of allowable settings?**
dbOF, dbUF (Hz)	0.036	Identical	Yes
kOF, kUF	0.05	Identical	Yes
T-response (small-signal) (s)	5	Identical	Yes

[21] OFF and operating at unity PF. Or set to ON with unity PF.
[22] Up to a maximum of 2.6%/second if requested.
[23] Refer to Default IEE 1547-2018 Setting Requirements, dated May 9, 2022

Table 7.8.3.2-3: Default Frequency-watt Settings for non-Inverter based DER and non-Certified inverters

Required Settings		Comparison to IEEE Std. 1547-2018 for Category I Default Settings	
Parameter	**Settings**	**Settings**	**Within ranges of allowable settings?**
dbOF, dbUF (Hz)	1	Much higher (Default is 0.036)	Yes
kOF, kUF	0.05	Identical	Yes
T-response (small-signal) (s)	10	Much higher (Default is 5)	Yes

The above mode settings are in accordance with the "Default IEEE 1547-2018 Setting Requirements", dated May 9, 2022. If a device does not have the above mode settings and is not within the scope of the "Default IEEE 1547-2018 Setting Requirements:, dated Dec 13, 2022, the device shall operate in unity power factor mode with any available grid support functions disabled.

7.8.3 Return to Service

The DER shall not connect or return to service following a trip (including any ground fault current sources) until detecting 5 minutes of healthy utility voltage and frequency. Detection and return to service function shall be performed by utility grade relay where utility grade relay is required. "Healthy Utility Voltage and Frequency" is defined by Table 7.8.3-1, in accordance with the Enter Service Criteria in IEEE Std. 1547-2018 section 4.10:

Table 7.8.4-1: Return to Service Parameters for DER

Utility Parameter	Default Value
Minimum Return to Service Voltage:	0.917 per unit of nominal voltage
Maximum Return to Service Voltage:	1.05 per unit of nominal voltage
Minimum Return to Service Frequency:	59.5 Hz
Maximum Return to Service Frequency:	60.1 Hz
Return to Service Ramp Rate	Refer to Section 1.5 in Default New England Bulk System Area Settings Requirement

8.0 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. All Company-designated relay functions and all synchronizing elements will be witness-tested/verified by the Company's personnel prior to energization.
3. A letter, written by the Customer or their assigned agent, indicating the protection and control scheme has been functionally tested in accordance with the Customer's submitted design as accepted by the Company, shall be completed prior to the Company's witness testing.
4. The Customer shall submit a testing and commissioning plan (TCP) to the Company for review at least 20 business days prior to the scheduled witness test. If needed, consult the Company for guidance on preparing a TCP. This activity will normally be performed as specified by Section 4.2.4 in the **RI SCDG.**
5. Inverter settings, as presented by EPRI's Common File Format for DER Settings Exchange and Storage, shall be submitted with the TCP. EPRI's Guidance Document can be found here[24], and is publicly available.
6. All required equipment test reports shall be submitted per ESB 751 prior to final TCP acceptance.
7. The TCP shall be finalized as accepted by the Company no later than five (5) business days prior to functional testing of the Company-designated protective devices.

9.0 Operating

1. The Customer's DER system shall maintain a power factor at the PCC in accordance with the RI SCDG between 0.90 leading or lagging (VAR or voltage support can also be considered within machine ratings) unless more strict requirements apply according to the Company's Impact or Detailed Study. Corrective equipment may be required and, if so, it will be at the Customer's expense; refer to ESB 750. It is the Company's expectation that the Customer will strive to maintain a power factor at their service point that does not adversely affect the power quality (PQ) of the Company's EPS; see ESB 750
2. The Company requires a Sequence of Operations (SOO) from the Customer. The Company also requires an operating description from the Interconnection Customer for normal, alternate, and emergency (if proposed) operations, if the Customer desires to operate in these modes and in the event of any changes to the existing procedures.
3. The Customer is responsible for performing all operating functions associated with their equipment and for maintaining all equipment under their ownership. The Customer shall arrange to have trained personnel available for the proper and safe operation of their equipment.
4. The Customer shall follow the Company's specified switching protocol upon commissioning, synchronizing, and return-to-service situations with the Company's distribution system operator; see ESB 755 for more information on Customer operating and maintenance responsibilities.
5. The Customer's service and backup service requirements from the Company's system shall be requested using the prescribed forms in the Company's Electric Tariff, R.I.P.U.C. 2243.
6. Where the Company is requested to supply demand pulse information (either analog or digital), its use is not intended for generator dispatch or control.

[24] https://www.epri.com/research/products/000000003002025445.

7. Should the Customer Facility experience unexpected tripping of their interrupting device, the Customer shall first perform their own extensive analysis of all possible causes for trips of their own system before attempting to resolve those issues through the Company.
8. The Customer shall provide relay event records upon request following a system disturbance.

10.0 Power Quality Monitoring

10.1 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 shall 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 generation. Third party PQ test methods and results may be submitted to the Company for review and acceptance. These verification tests shall include, at a minimum, the following in accordance with the Company's Electricity Tariff, R.I.P.U.C. 2243 and the limits and cost responsibilities specified in the RI SCDG:

- Check service point voltage for any discernible voltage fluctuation.
- Check service point frequency for any discernible frequency fluctuation.
- Check PCC power factor to ensure it is no less than 90% (leading or lagging).
- Check service point harmonic distortion to ensure limits specified in ESB 750 and the **RI SCDG** as applicable, are maintained. Current harmonic distortion shall not adversely affect voltage harmonic distortion, the Company Distribution EPS, or service to other customers.

10.2 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's ESB 750 and the RI SCDG.
2. If it is determined that system modifications or changes are needed in order to mitigate the disturbance issue, the cost of such modifications or changes shall be borne by the Interconnection 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 generation until such concerns are resolved to the Company's satisfaction.

10.3 Transient Overvoltage / Load rejection Overvoltage (LROV)

The DER facility shall limit its cumulative instantaneous overvoltage according to Figure 3 of IEEE Std.1547-2018 section 7.4.2. A certified DER can meet this requirement by submitting a testing certification document showing compliance with IEEE 1547.1-2020 Section 5.17.

Otherwise, most inverters have a 'self-protective overvoltage' setting in the inverters that, if enabled, is capable of tripping for no higher than 1.4pu voltage in 1ms or less clearing time. This set point is one acceptable means to meet the requirements if a letter from the inverter manufacturer is provided to the Company stating that this setting (or tighter) is enabled in the inverters to be installed on the site, and the inverter voltage response adheres to the curve in IEEE 1547-2018. 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's 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.

11.0 Facility Audit

The Company reserves the right to periodically audit the Customer's generation equipment installation and service connection for compliance with the Company's requirements.

12.0 Disconnection by the Company (Isolation)

Pursuant to Section 7 in the **RI SCDG**, the Company reserves the right to have the Customer remove their generation from the Company EPS at any time upon the Company's request. Normally, such requests result from the need to facilitate maintenance, test, or repair of Company facilities. The Customer's generator disconnect switch[25] may be opened by the Company (i.e., isolating the Customer's generating equipment), without prior notice to the Customer, for any of the following reasons:

- System emergency operations require such action.
- Company periodic checks of Customer's interfacing equipment reveal a hazardous condition, or lack of necessary maintenance for equipment necessary to protect the Company's EPS.
- Generating equipment interferes with other customers or with the operation of the Company's EPS.
- When required protective relaying and/or tele-protection is altered, inoperable, or missing When required special equipment necessary for operating control (*e.g.*, telemetering/SCADA) on the Company's EPS is inoperable or missing.
- Parallel operation, other than for **RI SCDG** testing of type tested inverters, prior to Company approval to interconnect. testing of type tested inverters, prior to Company approval to interconnect.
- Failure to make available records of verification tests and maintenance of the Customer's protective devices designated by the Company, unless otherwise specified in the RI SCDG.
- Situations where the area EPS is in a non-normal operating scenario and the generator has not been studied for interconnection in that specific operating scenario.

13.0 REVISION HISTORY

Version	Date	Description of Revision
1.0	06/01/07	Initial version of new document superseding all previous revisions of ESB 756.
1.1	07/29/11	September 2010 ESB 750 Series Errata changes, formatting, and general editing.
2.0	08/06/12	Revised and formatted incorporating technical requirements of RI PUC 2078 Nov. 2011.
3.0	08/03/17	June 2017 revised for RI PUC 2163 Feb 26, 2016, IEEE 1547IEEE 1547-2018a amendment, and technical updates
3.1	12/15/17	October-December 2017 interim amendments to Sections 7.6.11, 7.8, and Figures 2 & 5.
3.2	02/09/18	January-February 2018 interim amendments to Sections 7.6.11, 7.6.12, and 7.8.
4.0	06/29/18	June 2018 revised for IEEE 1547and updated Rhode Island Energy practices.
5.0	11/15/19	November 2019 revised for updated Rhode Island Energy practices and RI PUC 2180.
6.0	12/04/2020	December 2020 revised for updated Rhode Island Energy practices and RI PUC 2180.
7.0	12/01/2021	December 2021 revised for updated Rhode Island Energy practices and RI PUC 2180.
8.0	05/01/2023	revised for updated UL-1741 3rd edition and IEEE 1547 SB, Company revision to RI Energy, updated RIE practices and RI PUC 2240
9.0	11/01/2025	Updated for newer protection technologies and 1741-SB requirements.

[25] *Refer to Section 7.4 regarding technical requirements for draw-out breakers over 600V and the Company's ESB 750.*

14.0 EXHIBITS ATTACHED

EXHIBIT 1: Company Requirements for Projects Not Eligible for the Simplified Process

These are Company items to be considered in the Customer's DER Project Schedule.

ID	Activity Description	RI SCDG § or ESB ref.
Project Definition & Conceptual Analysis Phase		
1	Customer R.I.P.U.C. 2240 Exhibit C Expedited/Standard Interconnection Application Form w/technical submittal & prelim. design received	3.2 or 3.3, Figure 1, Table 1
2	Company Preliminary Technical Assessment & cost estimate for Impact or Detailed Study	3.0, Table 2
3	Company R.I.P.U.C. 2240 Exhibit I Retail Connection Agreement executed with Customer	Exhibit I
4	Customer commits to Impact or Detailed Study and provides advance payment	5.0
Final Design Review Phase		
5	Company completes Impact or Detailed Study/Service Plan	3.2 or 3.3, Figure 1, Table 1
6	Customer commits to utility system modifications in Impact or Detailed Study/Service Plan and provides advance payment	4.0, 5.0
7	Customer's project schedule and final design & specifications received	4.0 – 8.0, ESB 750 & 752 or 753 or 754 or 758
8	Company reviews Customer's design & returns comments	4.0 – 8.0, ESB 752 or 753 or 754 or 758
Installation Progress Review Phase		
9	Customer's corrected design, test reports & settings received	4.0 – 8.0, ESB 752 or 753 or 754 or 758
10	Company reviews Customer's design & returns comments	4.0 – 8.0, ESB 752 or 753 or 754 or 758
11	Company field audit of Customer's installation progress	4.0 - 6.0
Installation Compliance Verification Phase		
12	Customer's advance notice of functional testing received	4.2.4, ESB 755
13	Electrical inspection certification approval received from municipal codes enforcement	ESB 750 & 752 or 753 or 754 or 758
14	Customer's acknowledgement of satisfactory wiring & relay calibration tests received	4.2.4, ESB 755
15	Company witness of Customer's functional testing	4.2.4, ESB 755
16	Company field audit of Customer's service connection	4.0 – 6.0, ESB 750 & 752 or 753 or 754 or 758
17	Customer resolves open items	ESB 750 & 752 or 753 or 754 or 758
Energization & Synchronization Phase		
18	Verification testing satisfied	4.2.4
19	Company's metering installation complete	8.0, ESB 750 & 752 or 753 or 754 or 758
20	Company's supply system interconnection complete	4.0, 5.0
21	Company review/acceptance of Customer's resolved open items	
22	Customer's Certificate of Completion received (and energization sequence plan for interconnections >600V)	3.2 or 3.3, ESB 755
23	Company proceeds with energization	

ID	Activity Description	RI SCDG § or ESB ref.
24	Customer is permitted to synchronize generation facility in parallel to the Company's supply	
Project Closeout Phase		
25	For interconnections >600V, remainder of Customer's protective system functional testing documented in an acknowledgement letter submitted to the Company within 10 business days after energization	ESB 755
26	Customer's as-built design drawings received within 90 days for interconnections >600V	ESB 750 § 1.7
27	Company reconciliation of project costs with Customer	When requested by Customer.

EXHIBIT 2: Reference Maps of Rhode Island Energy Secondary Network EPS Areas

Pawtucket
https://www9.nationalgridus.com/narragansett/home/energyeff/network/Eastern/Pawtucket_Network_Feeder_10-02-12.pdf

Providence:
https://www9.nationalgridus.com/narragansett/home/energyeff/network/Eastern/Providence_Network_Feeder_10-02-12.pdf

Rhode Island Energy customers in the downtown districts of Pawtucket and Providence should check the Rhode Island Energy websites above. **If the street location is highlighted (or near) the red line, contact the Company's Customer Energy Integration department** via E-mail addressed to Distributed.Generation@rienergy.com to determine if the proposed location is served in Rhode Island Energy's Secondary Network area.

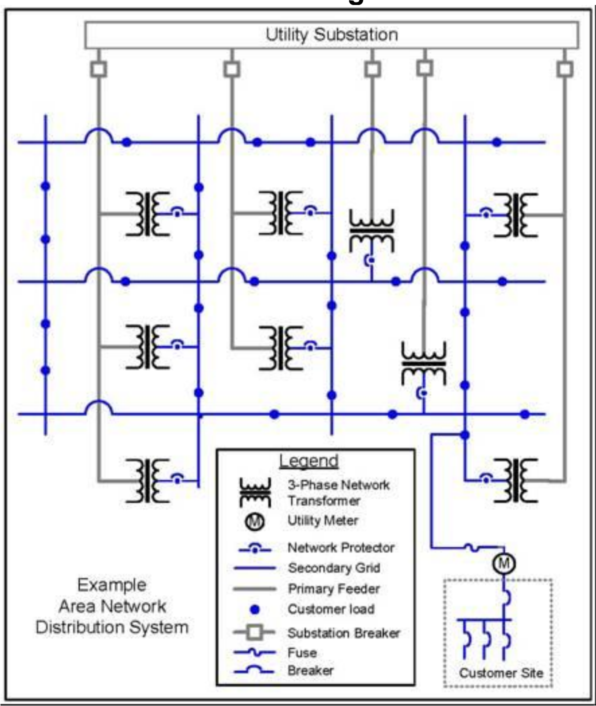
<u>EXHIBIT 3</u>: Distribution Secondary Grid Network Description

Rhode Island generally has two types of electrical distribution systems: radial and distribution secondary network systems. While the vast majority of customers are served from radial power systems, some customers in the downtown districts of Pawtucket and Providence in Rhode Island are served by distribution secondary network systems; see **Exhibit 2** for area maps. These systems are designed to meet the higher reliability needs, dense load levels, and limited space commonly encountered in urban areas.

A distribution secondary network system delivers electricity through a complex and integrated system of transformers and underground cables that are connected and operate in parallel. Power can flow in either direction on the secondary service delivery lines, commonly called secondary distribution lines. The loss of a single line or transformer in a secondary network system does not cause an interruption of power, unlike radial systems where there is only one line and one path for power to flow from the distribution substation to the customer's point of service. If a radial system experiences an outage, service is interrupted to the customers until repairs are completed; this is less likely to be the case in a distribution secondary network system.

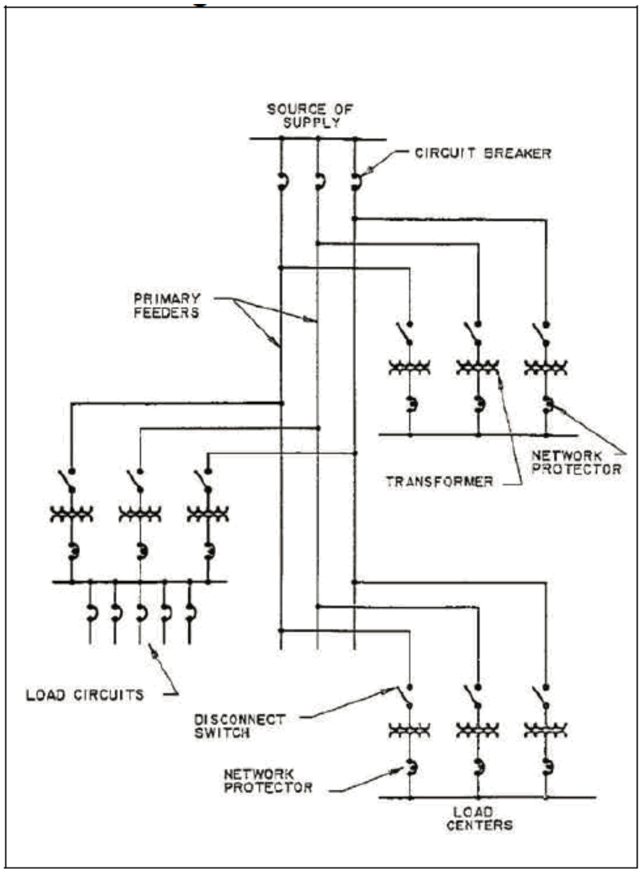
In distribution secondary network systems, devices called "network protectors" are usually arranged to automatically connect its associated transformer to the network system when conditions are such that the transformer when connected will supply power to the network and to automatically disconnect the transformer from the network when power flows from the network to the transformer. The integration of DER into a distribution secondary network system may result in network protectors exceeding their original design criteria or nameplate ratings.

Example Distribution Secondary <u>Grid</u> Network Diagram



Underground secondary grid (area) network systems deliver power to each customer through a complex and integrated system of multiple transformers and underground cables that are connected and operate in parallel.

Example Distribution Secondary <u>Spot</u> Network Diagram



Spot networks are similar to grid (area) networks except they serve a single premise.

<u>EXHIBIT 4</u>: Recommended Guidelines for Residential and Commercial Single-line Diagram Submittals

Refer to **Figures 2** and **3** for typical illustration and symbology.

1. Identify the project, Company's electric service order (ESO) number, location and submitter's name and address.
2. Indicate standard and any non-standard system voltages, number of phases, and frequency of the incoming circuit. Indicate wye and delta systems; show whether grounded or ungrounded.
3. Identify cable, conductors and conduit, the type and number. The Company is interested in how the power is getting from the service point to the protective equipment.
4. Identify wiring troughs and/or junction boxes where used.
5. Use standard symbols. See **NFPA 70B** or **IEEE Standard 141** for symbols in typical electrical single-line diagram development.
6. Identify the service equipment's switch and fuse or circuit breaker as to manufacturer, type, rating, catalog number, etc. Service equipment must be able to safely interrupt the maximum available fault current from the supply; refer to **NEC** Articles 110 and 230.
7. Show billing meter trough or instrument transformers' cabinet (C.T. cabinet) in circuitry. Indicate source and load for the circuit. Refer to Section 7 in the Company's **ESB 750** for acceptable metering configurations.
8. Identify other protective devices and ratings. Include ratings in volts and amps, the interruption rating, and type and number of trip coils on circuit breakers. Also, note any special features of fuses (current limiting, dual element, etc.).
9. Identify ratios of current and potential transformers, taps to be used on multi-ratio transformers, and connection of dual ratio current transformers if used.
10. Identify any relays, if used, and their functions. Indicate which interrupting device(s) are tripped by the relay(s) used.
11. Show connections, winding configuration, and ratings of power transformers for any to be used. Show the transformer impedance and X/R ratio.
12. Indicate the connections, winding configuration and ratings of grounding transformers if any are to be used. Show the impedance and X/R ratio.
13. Identify Generator Disconnect and its ratings, the service point, and the PCC.
14. Provide catalog cut-sheets clearly identifying exact model to be installed for devices and equipment of mutual interest to the Company and of the Customer. Equipment shall be inclusive but not limited to the main service arrangement, any transformer in the circuit path between the point of common coupling and the generator, the generator interrupting device, the utility disconnect, and inverter(s) and/or relay(s).

FIGURE 1: Sample Residential Photovoltaic Distributed Generator Installation – Single Phase, Net Metered

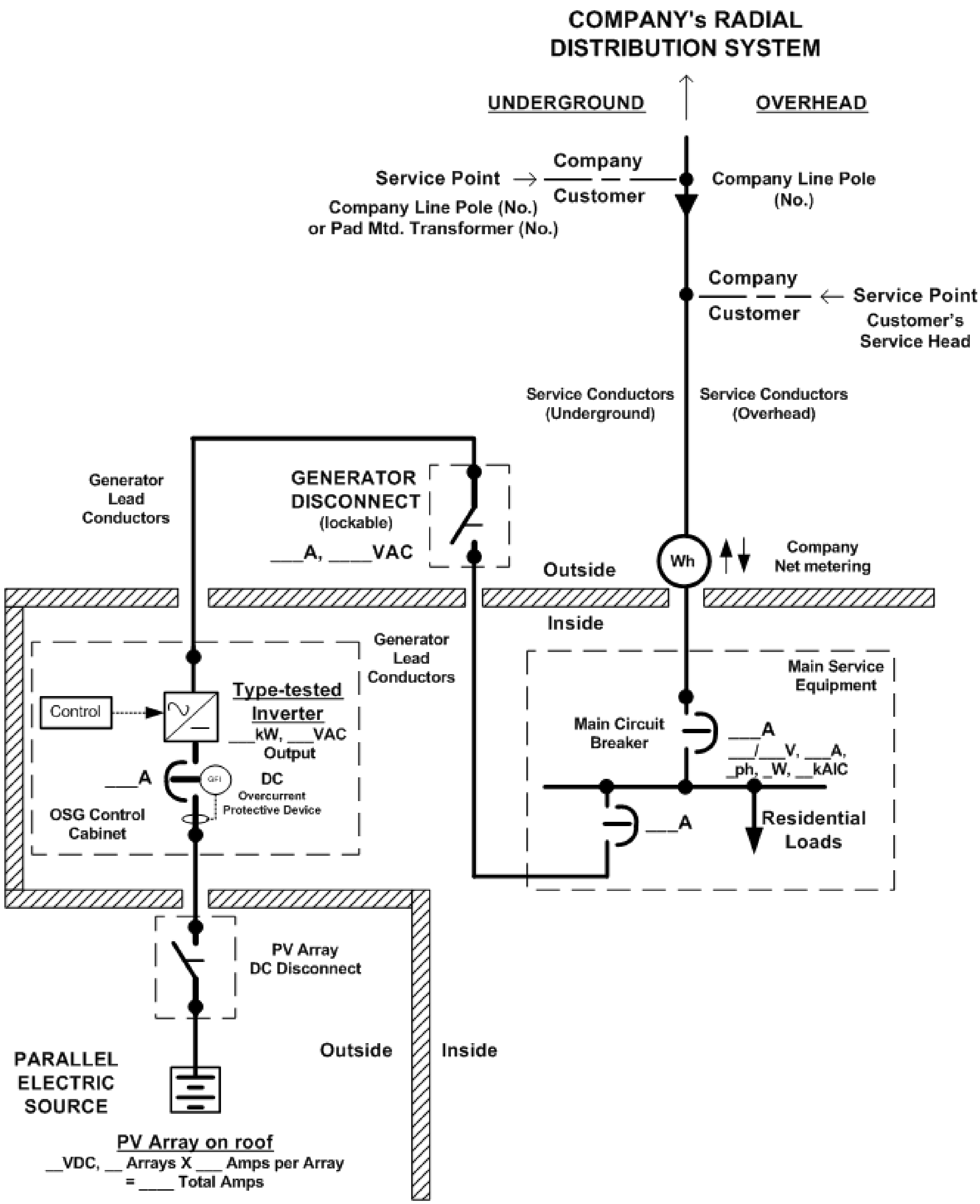
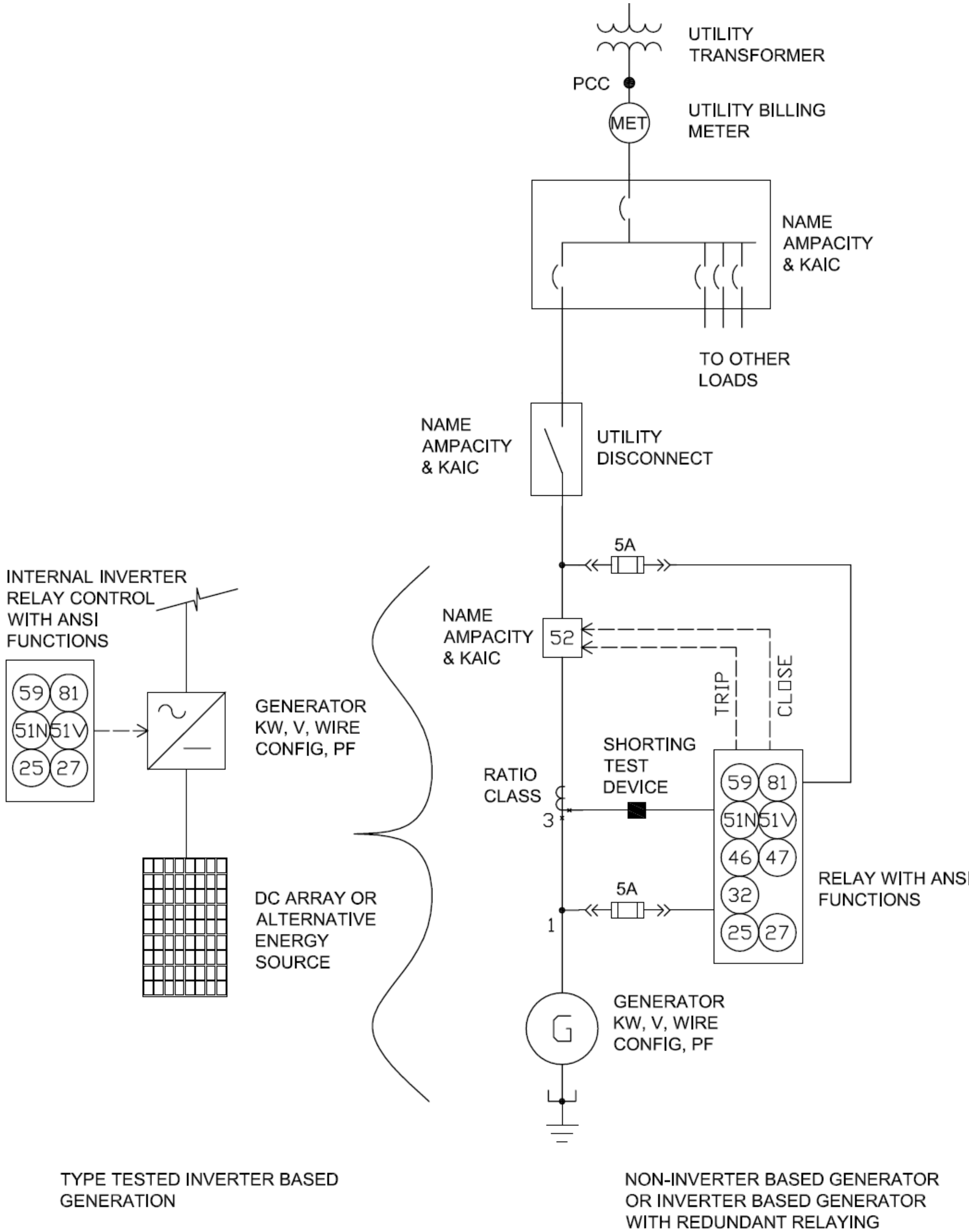


FIGURE 2: Sample Distributed Generator One-Line Diagram



[TYPICAL ONLY]

FIGURE 3: Typical Symbology for Electrical Drawings

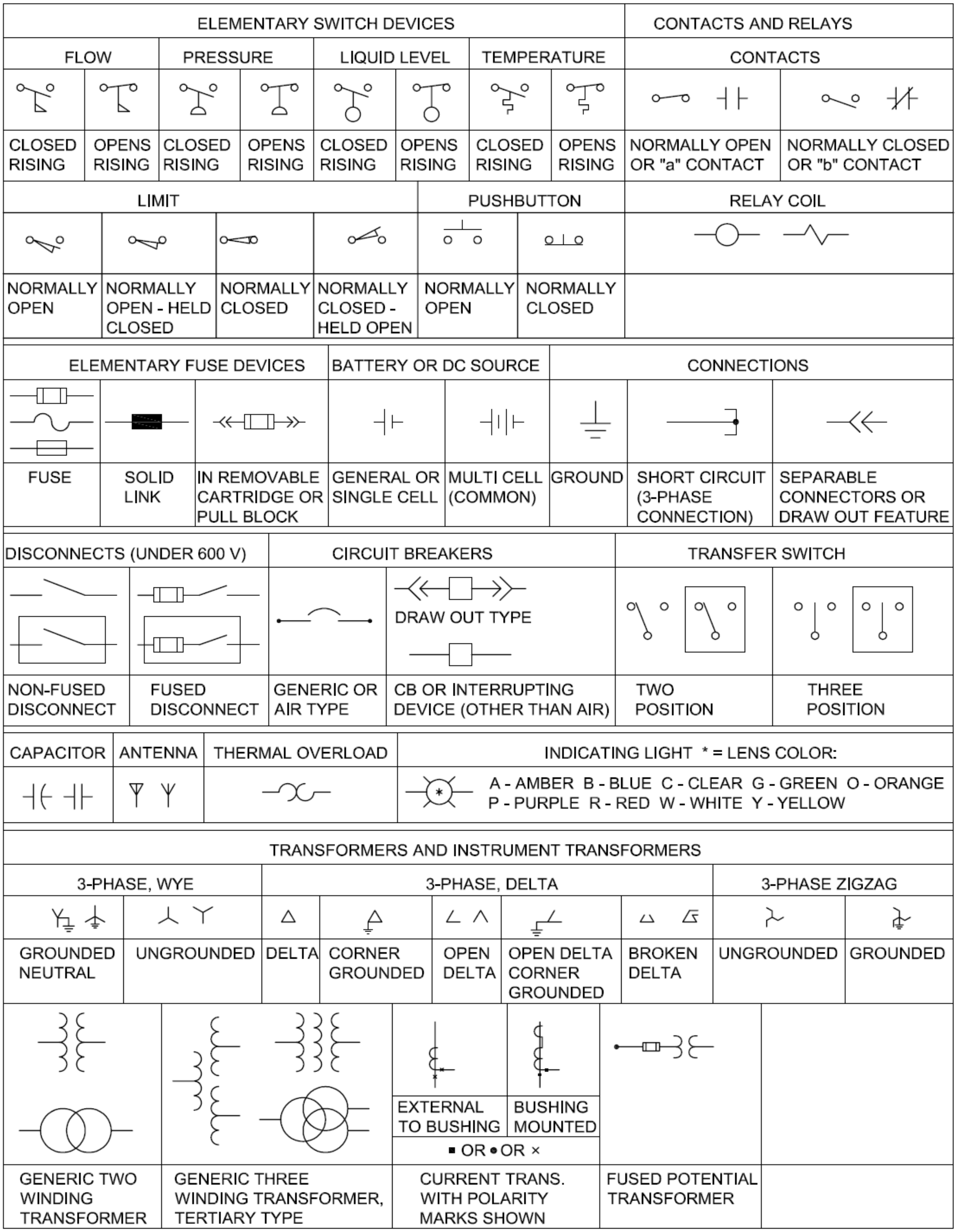


EXHIBIT 5: Recommended Guidelines for Functional Single-line Diagram Submittals

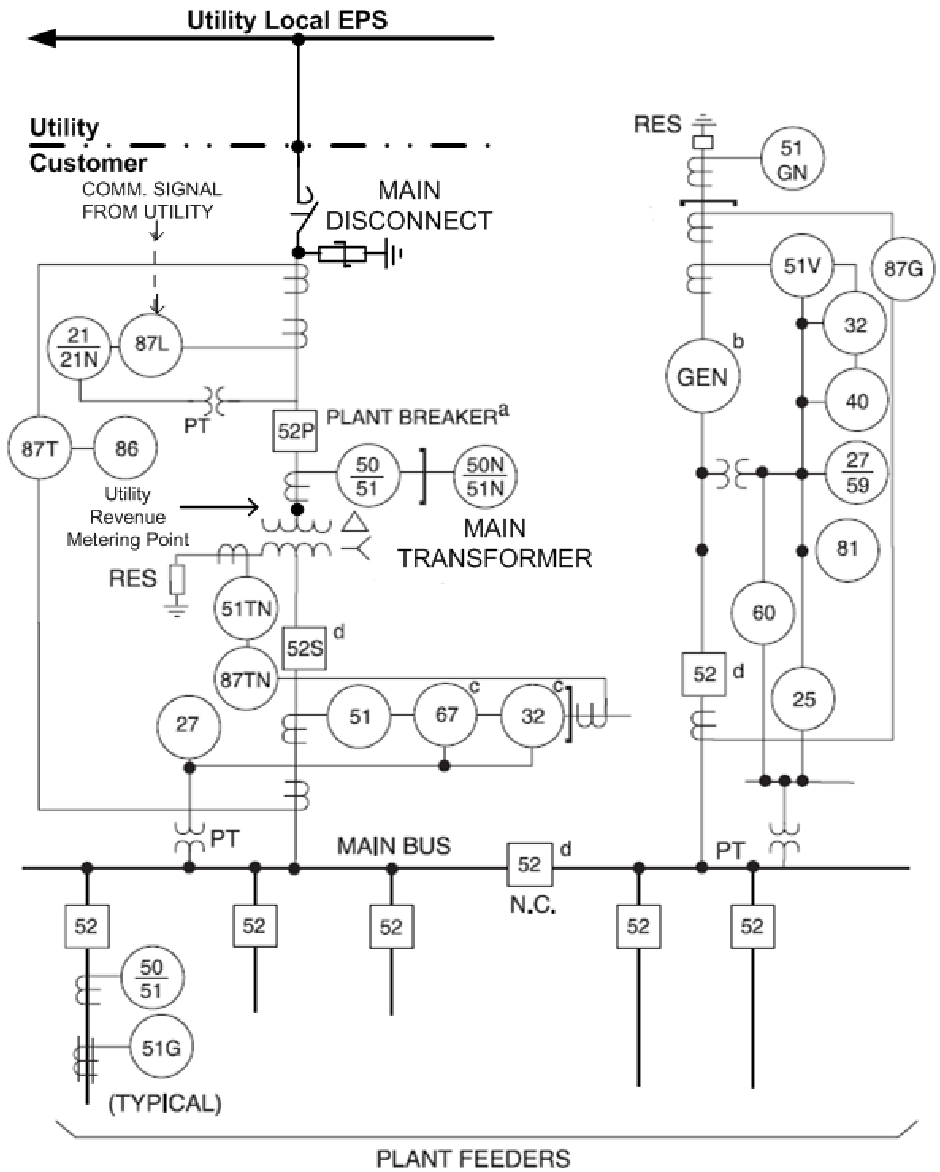
Refer to **Figures 1** and **2** for typical illustrations.

In addition to **Exhibit 4**:

15. On functional single-line diagram submittals, industry standard device numbers are necessary. Refer to the following List of Standard Device Numbers (See latest edition of **ANSI C 37.2**):

Device Number	Function
25	Synchronizing Device / Synchronism check device
27	Undervoltage Relay
32	Directional Power Relay
46	Negative Sequence Voltage
50	Instantaneous Overcurrent Relay
51	Phase Overcurrent Relay
51N	Neutral Overcurrent Relay
51G	Ground Overcurrent Relay
51V	Overcurrent Relay, voltage restraint
51C	Voltage controlled overcurrent
52	Breaker
52R	Recloser
59	Overvoltage Relay
59G	Neutral Over Voltage Relay
59N	Zero Sequence Over Voltage Relay
62	Time-delay Stopping or Opening Relay
64	Ground Protective Relay
81	Over and Under Frequency Relay
86	Lockout Relay
87	Differential Relay

FIGURE 4: **Sample Functional Single-Line Diagram**



NOTES:
a. A fused interupter switch may also be used instead of the breaker. If fused interrupter is used, relaying associated with the transformer is not used.
b. In-plant generator for partial plant load and back-up.
c. Devices 67 and 32 are directional. Polarity of CTs and PTs must be verified.
d. Overcurrent and bus differential protection should be provided for the main, generator, and tie breakers, but protection is not shown here. See IEEE Std. C37.95 and C37.97.

Trip function lines not shown.
See IEEE Std. 242 Buff Book “Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems” for more information.

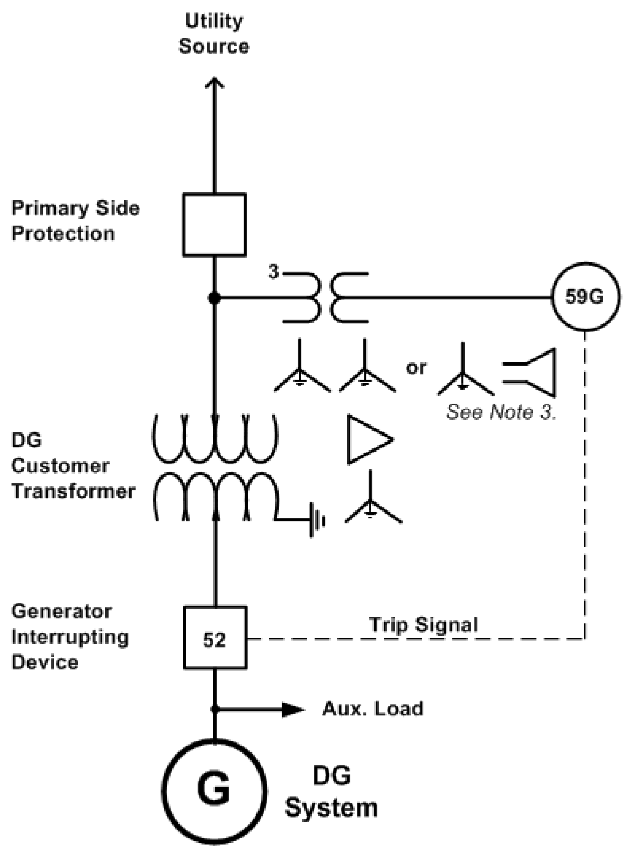
[*TYPICAL ONLY*]

FIGURE 5: Typical $3V_0$ Requirements for Local EPS Ground Fault Detection

The Company requires ground fault protection on any system that can be a generation source to protect any equipment that can be parallel supplied from two sources. In the cases where the primary winding of the transformer supplying the facility is delta, a "**zero-sequence**" voltage or "**$3V_0$**" scheme is required. Typically, this is implemented by installing potential transformers (PTs) on the primary system as a source to a voltage sensing relay containing a ground overvoltage device function (59N or 59G) capable of detecting the presence of a single line-to-ground fault on the Local EPS.

Notes:

1. *The Company may waive this requirement depending on the restrictions of the local EPS.*
2. *Trip signal is shown to remove generator from Company's EPS at the generator interrupting device. Alternatives may be proposed for Company approval for alternative arrangements.*
3. *Yg-Broken Delta arrangement is typical of an electromechanical relay installation while Yg-Yg is commonly applied for a microprocessor relay installation.*



-- INFORMATION ONLY --

-- SIMPLIFIED DIAGRAM NOT ALL DETAILS SHOWN --

<u>EXHIBIT 6</u>: Typical Overhead Primary Service Configuration in RI for Large DER Installations

The Customer will be required to install a pole to the Company's specifications on which the Company will install cross arms and dead end the Company's primary service conductors. This point will be the physical Point of Common Coupling (PCC). At this pole the Customer-owned, 3-phase gang operated, Generator Disconnect switch can be installed and connected to the Company's primary service conductors by the Customer.

All Company-owned service lateral facilities and equipment on private property will require easements. These easements will be the responsibility of the Customer to obtain in accordance with the Company's specific electric service requirements; see ESB 750.

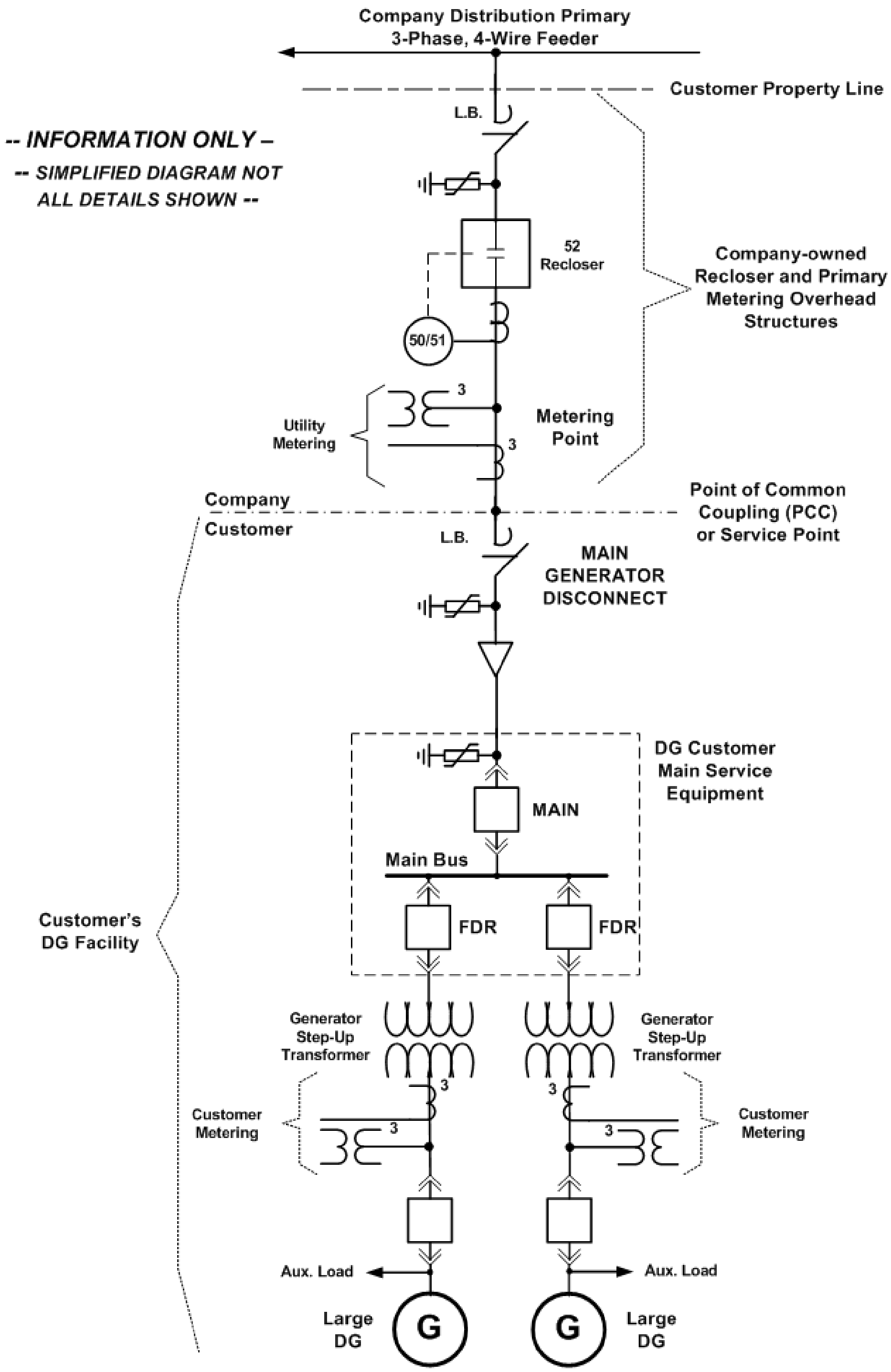


EXHIBIT 7: Net Metering Compliance Verification Checklist (Simplified Process)

Account Number: ____

Email:_____________________

Customer Name: ____ **Phone #**___________________
Last First **Work Phone #**______________

Service Address: ____
Number Street Town/City Zip

Billing Address: ____
Number Street Town/City Zip

Qualified Installer: _______________________ **License #**__________ **Phone #**___________________
Last First (if available) **Cellular #**__________________

Address: ____ **FAX #**_____________________
Number Street Town/City Zip **Email:**____________________

✓ **Verify One-Line Diagram (installed equipment)**

_______ UL 1741 Certified Inverter Model ________________________________

_______ Software version ________________________________

_______ Company billing meter s/n _________________ Net-meter One Meter Option: **YES**___ **NO**___

_______ Inspection received? **YES**___Number _____________________ (*attach copy of approval certificate*)
NO___, then stop and await inspection approval.

✓ **Verify Plot Plan (equipment's location)**

_______ "Generator Disconnect Switch" is **at agreed location**: **YES**___**NO**___.

_______ "Generator Disconnect Switch" **is labeled** as such: **YES**__**NO**__.

_______ **Label is at meter location** to identify location of Generator Disconnect: **YES**__**NO**__.

✓ **Verify DG System Is Operating (producing power)**

_______ Verify "Generator Disconnect Switch" is **Open.**

_______ Verify voltage is **zero volts** on DG side of open "Generator Disconnect Switch": **YES**___**NO**___.

_______ **Close** "Generator Disconnect Switch".

_______ Verify DG inverter **alarms** and **voltage present** on utility side of "Generator Disconnect Switch":
YES___**NO**___.

✓ **Restoration of Utility Power Test**

_______ **Open** "Generator Disconnect Switch", **pause at least 1 to 2 minutes**, then **Close** "Generator Disconnect Switch". Record time when "Generator Disconnect Switch" is closed: ___________

_______ Record time when **DG Inverter starts** producing power: ___________________. Is the time between the "Generator Disconnect Switch" closure and when DG Inverter permits synchronization to utility source **greater than 5 minutes**? **YES**____**NO**____

✓ **24-hour Telephone Number Contact**

Name: ____ **Number** (____)_______________

Performed by: ____________________________ ***signature***:_________________________**Date:** _______
Name (Customer's qualified installer)

Witnessed by: ____________________________ ***signature***:_________________________**Date:** _______
Name (Company witness)