

**SUPPLEMENT TO**

**SPECIFICATIONS FOR**

**ELECTRICAL INSTALLATIONS**

**PRIMARY METER POLE**

**ELECTRIC SYSTEM BULLETIN No. 753**

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**Niagara Mohawk**

A **National Grid** Company



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## I. INTRODUCTION

### A. Purpose

1. This Supplement to Electric System Bulletin (ESB) #750 provides specific Company guidance for those Customers whose service point is a customer owned primary meter pole.
2. **It is important that the Customer and their engineer or contractor obtain and refer to the Specifications for Electrical Installations book (ESB #750) in conjunction with this supplement for these installations.**
3. These requirements are to insure that the electric facilities will render satisfactory service to the Customer, and will not interfere with the electric supply to others served by the Company's system.
4. This type installation is available only for Overhead-to-Overhead Line connection.

### B. Scope

1. This bulletin provides more complete information for electric service installations utilizing an Outdoor Receiving Installation served from an Overhead Line at 2400,4160, 4800, or 13,200 Volts.
2. These requirements do not cover the Customer's complete electrical installation design but concern only those points in which the Customer, architect, their Consulting Engineer, Electrical Contractor, Equipment Manufacturer, and the Company have a mutual interest.
3. Where appearance is a factor in the installation of this receiving structure, or a Customer is proposing an Underground Line Connection, a metal-enclosed switchgear installation is required, see *Electric System Bulletin No. 758*.
4. Where the Customer's demand is greater than the Company's allowable limit for the supply voltage, a substation or a metal-enclosed switchgear is required, see *Electric System Bulletin No. 752 or No. 758* as applicable.
5. Company Furnishes
  - a. The Company will furnish and install the service lateral complete with dead end insulators, strain clamps and clevises.
  - b. The Company will furnish instrument (metering) transformers with mounting frame, meter, and a meter trough.
  - c. The Company will furnish the meter cable between the instrument transformers and the meter trough.
6. Customer Furnishes
  - a. The Customer will furnish, install, own, and maintain all materials required to complete the installation not explicitly mentioned in I.B.5 above.

### C. Customer's Responsibility

**(Refer to Figures 1 & 2 for illustrated representation.)**

1. The Customer, their Engineer, Contractor, and supplier should provide a safe, modern, adequate installation with ample provision for future needs.
2. The Customer shall obtain building permits and/or zoning variances as required for construction.
3. The Customer shall be responsible to have all electrical and physical design documents prepared by a design professional, in accordance with Section 1.7 of ESB 750, and as further detailed later in Section I.G of this bulletin.

## **D. Cooperation**

1. For a specific installation it is essential the Company meet with the Customer or their representative.
2. The information the Customer or their contractor furnishes to the Company in regard to the Customer's proposed electrical installation shall be in **writing**.
3. If significant changes are made to the design or scheduling of the installation by the Customer, initial information furnished by the Company shall be subject to review and possible modification.
4. When an issue arises which is not contained in this booklet or *Electric System Bulletin #750*, the Company invites inquiries.

## **E. Codes and Standards**

1. The Customer's electric service equipment and its installation shall conform to the requirements of the latest edition of the National Electrical Code (NEC), National Electrical Safety Code (NESC), Rural Electric Association (REA), National Fire Protection Association (NFPA), all local ordinances, building codes, and Company requirements and specifications.
2. Components shall conform to the latest editions of the following national standards and codes:

<u>Component</u>	<u>Applicable National Standard</u>
Cable	ICEA
Power Switches and Fuses	ANSI C37
Lightning Arresters	ANSI C62
Insulators	ANSI C29, EEI TD-17
Pole	ANSI O5.1, EEI TD-103
Crossarm	EEI TD-90
Guy Wire	ANSI C7, ASTM A475
Anchors	ANSI C135.2
Terminations	NEMA
Grounding	IEEE 80

3. The Customer should consult their insurance carrier for any special safeguards, which the carrier may require for the Customer's outdoor receiving installation.

## **F. Inspection**

1. To protect the Customer's interest, as well as its own, the Company requires the Customer to furnish satisfactory evidence from the local authority having jurisdiction as to the safe condition of their entire electrical installation before energizing the service to a new installation of re-energizing a service that has been disconnected for more than twelve (12) months.
2. This may be in the form of an approval or certificate from the New York Board of Fire Underwriters or other inspection organization acceptable to the Company.
3. Catastrophic occurrences such as fire, flood, etc. shall require a new certificate as to the safe condition of the entire electrical installation.
4. Application for inspection should be made before the work is started.
5. When wiring is replaced, altered, or extended an approval or certificate shall also be obtained to assure compliance with safety requirements.

## G. Compliance

1. Prior to the meeting indicated above (section D), the Customer shall provide three (3) copies of a fully dimensioned plot plan indicating property lines, building outlines and detail of the preferred location for electrical service equipment, as well as the proposed location of any buried facilities.
2. After the meeting, the Company will designate the pole location from which the primary service will be extended.
3. The Company will respond, indicating the route of the service lateral.
4. The Company's Consumer Relations Department will advise the Customer concerning any contribution required in accordance with the Company's filed tariff.
5. **THE CUSTOMER SHALL SUBMIT THEIR PLANS AND SPECIFICATIONS TO THE COMPANY BEFORE ORDERING EQUIPMENT OR STARTING WORK to insure that the proposed design for the electric service installation conforms to Company requirements.**
6. For general compliance with these specifications, the Company normally limits its review to the details of the service lateral, the service disconnect and protective device, the primary meter pole location, and the location of the metering equipment.
7. Required Documents and Submission Process

The required delivery of the design documents shall be as described in submittal stages "a" through "d" below. Drawings shall be originals prepared by the Customer's retained design professional and comprehensively detail the design of the electrical facility on a single sheet to permit full interpretation and understanding of all aspects. The drawings shall be prepared in conformance with ANSI Y32.2, IEEE 141 and IEEE 446 symbol and drafting nomenclature. All devices specified shall be of power utility grade and not industrial grade.

In order to speed and efficiently facilitate review, no portion of a submission should be sent until every element of the package is complete, final and deliverable in a single package in any of the following stages. Unless otherwise requested and at the sole discretion of the Company, no individual document, or partial design, of a submission will be accepted for Company review until the Customer has declared that the package is complete. In all instances, six (6) complete sets of design documents shall be submitted for Company review and acceptance.

### a. PRELIMINARY SUBMITTAL

Along with the completed service application, the following shall be submitted:

- Plot plan
- Functional single line diagram with proposed ratings of disconnecting devices, overcurrent protection, transformer size and impedance.

### b. DETAILED ELECTRICAL DESIGN SUBMITTAL

Along with the Customer's written notice to proceed, the following shall be submitted:

- Complete functional single line detailing all devices up to, and including, the Customer's secondary protective device. It should include: all protective relays in sufficient detail to show intended operation; all instrument transformers with ratios, including excitation curves; power and station service transformers with ratios; etc.
- Specifications:
  - Switch.

Lightning Arresters.

Fuses and Fuse Cutouts, or Circuit Breaker or High Voltage Interrupter if used.

Conductors.

Insulators.

Pole and Hardware.

Power transformer.

- The switch manufacturer's certification documents:

Switch manufacturer's certification to ANSI standard test requirements for load break capability.

Note: Ice Test shall be required to pass for 1/2" ice loading.

A statement indicating that the switch has been tested and will operate properly with a 10,000 ft.-lb. (2000 lbs. tension per conductor) torque applied to the switch mounting frame.

Note: For example, if one outer phase conductor disconnects, can the switch open in a fail-safe mode?

- Where circuit breakers or high voltage interrupters are used for the main overcurrent device:

List of proposed relays.

Electrical AC ELEMENTARY, if required by protective device, in sufficient detail to show the functional control operation of the station. The elementary schematic diagram shall be in three-line format and show, by means of graphic symbols, all devices having any interaction with the tripping function of the main protective device. Specifically, it shall include all individual items of equipment, devices within the equipment, their coils, contacts, windows, terminals, AC source, and each connection (wire, cable or bus) between equipment and devices.

Electrical DC ELEMENTARY, if required by protective device, in sufficient detail to show the functional control operation of the station. The D.C. elementary schematic diagram shall show, by means of graphic symbols, all devices having any interaction with the tripping function of the main protective device. Specifically, it shall include all individual items of equipment including batteries, battery charger, devices within the equipment, their coils, contacts, windows, terminals, and each connection (wire, cable or bus) between equipment and devices. (Note – Ladder-type diagrams are not acceptable.)

Relay panel drawings.

Control house layout.

- Electrical Assembly and Layout drawings of the Primary Meter Pole.

- Manufacturer's switch detail drawings showing as a minimum:

The proposed switch mounted as indicated in Figure 3, 3A or 4.

Phase-to-phase and phase-to-ground clearances for switch components in the open and closed position.

Should the installation have any accessory components, i.e. interrupter devices, outriggers, etc. the details of these shall also be included in this drawing.

Expanded details of the hardware connections on the switch, mounting, and operating mechanism.

A bill of material identifying the quantity, material, size, model, and catalog number of all components associated with the switch including the switch itself, mounting frame, and the operating mechanism and hardware.

A table of electrical characteristics, B.I.L., Interrupting Amperes, Continuous Amperes, etc.

The switch nameplate showing catalog number, switch ratings and certifications.

A unique catalog number, which identifies the complete switch package as depicted.

- Grounding plans and details.
- Meter conduit and Meter Panel drawings, if meter is remote from the Primary Meter Pole.
- Transformer nameplate drawing.

c. FINAL, FOR-CONSTRUCTION SUBMITTAL

A complete set of all drawings and equipment specifications outlined above, marked final/for construction shall be submitted a minimum of four (4) weeks in advance of proposed energization. Also, at this time the manufacturers' test reports for the power transformer and, if used, circuit breaker or high voltage interrupter shall be submitted. When applicable, a list shall be submitted of proposed relay settings based on a formal relay coordination study. Settings shall not be shown on drawings. This is the end of the design process. The full set of design professional sealed final documents shall then be submitted for review in total by the Company.

d. FINAL, AS-BUILT IN FIELD SUBMITTAL

Once construction is complete and the service energized, a full set of the drawings in item c above shall be submitted within 90 days. They shall accurately document the as-built status of the project, including any deviation from the final for-construction design drawings, and again be sealed by the Customer's design professional.

8. The Company reserves the right to review the installation as it progresses.
9. An authorized representative of the Company will examine the Customer's installation before it is energized to insure compliance with these specifications.
10. The Customer shall maintain a ten (10) foot minimum clearance from an energized Company distribution line for work and structure placement.
11. See Figure 6 for required electrical installation clearances.

## II. DEFINITIONS

Note: Definitions as used in this specification are provided in the "**Specifications for Electrical Installations**" book (ESB#750), Section 2.

## III. GENERAL

### A. Access

1. Facilities shall be provided so that authorized Company Employees and vehicles have access to the Customer's electric service installation and Company-owned Metering equipment.
2. The Customer shall insure that accessways are free of vehicles, equipment, or other obstructions.

### B. Limits of Primary Services Available

1. Single phase, 60 Hz

<u>Wires</u>	<u>Nominal Voltage</u>	<u>kVA Limit</u>	<u>Notes</u>
2	2.4 kV, L-N	100	a, d
2	7.62 kV, L-N	100	
2	2.4 kV, L-L	100	a, d
2	4.8 kV, L-L	100	a

2. Three phase, 60 Hz

<u>Wires</u>	<u>Nominal Voltage</u>	<u>kVA Limit</u>	<u>Notes</u>
3	2.4 kV Delta	500	a, b, d
4	4.16 kV Wye-Grounded	1,000	a, b
3	4.8 kV Delta	1,000	a, b
3	12 kV Delta	1,000	a, b, d
4	13.2 kV Wye-Grounded	2,500	c

**Notes to Section III.B.1 & 2 above:**

- a. Non-Standard service voltage.
- b. New installations shall conform to clearances and ratings for 13.2 kV, three phase service.
- c. Maximum limit may be less depending upon supply and location.
- d. Where applicable.

**IV. SERVICE CONNECTIONS**

**A. General**

1. The Company reserves the right to designate the location of both ends of the service lateral.
2. The Company will construct, own and maintain overhead service laterals in the voltage range from 2,400 volts to 13,200 volts inclusive.
3. All connections, permanent or temporary between the Company's overhead service and the Customer's primary meter pole will be made by the Company.
4. The structure or riser shall be capable of withstanding 2000 lbs. tension for each service conductor.
5. The Customer shall furnish or obtain all right-of-way easements required by the Company between the Company's line and the Customer's primary meter pole on the Customer's premises.
6. The Company will provide an appropriate form for this right-of-way purpose upon request.
7. The Company's normal primary service voltage range measured at the point of delivery is between plus or minus five percent ( $\pm 5\%$ ) of its nominal voltage rating and plus or minus ten percent ( $\pm 10\%$ ) under abnormal conditions.
8. The Customer shall consider the installation of their own voltage regulation equipment if necessary.

**B. Primary Meter Pole Location**

**Factors to Consider:**

1. A field inspection by Company representatives will determine the location of the Customer's primary receiving structure.
2. Appearance and use of this structure should be seriously considered.
  - a. The Company recommends that it not be used for schools, or installed near the front of a building.
  - b. A metal enclosed switchgear installation should be considered for these locations.
3. The overhead primary lateral should be short, direct, and clear of trees, vegetation, buildings, storage space, or other possible occasion for work above ground level.
4. The Customer's overhead conductors shall have a minimum clearance of 22 feet from final grade.
5. Operation and future maintenance of the primary meter pole shall be considered.

## V. CUSTOMER SERVICE EQUIPMENT

(See Figures 3, 3A and 4 for typical assembly.)

### A. Rating Requirements

1. The service equipment shall be suitable for the maximum fault current available at its supply terminals.
2. The maximum fault available at the transformer primary is as follows:

<u>Service Voltage</u>	<u>Available Fault</u>
4.16 kV	25,000 kVA
4.8 kV	25,000 kVA
13.2 kV	150,000 kVA

### B. Receiving Structure Requirements

1. Pole:
  - a. The Pole shall be a Class 5, full length penta treatment, conforming to the standards of EEI TD-103 and ANSI O5.1.
  - b. The field conditions will determine the required height.
  - c. Pole shall be a minimum of 40 ft. in height, set 6 ft. minimum depth.
2. Crossarm:
  - a. The crossarm shall have 6 pins.
  - b. The crossarm shall measure 3-1/2" x 4-1/2" x 8'-0" minimum, conforming to specifications of EEI TD-90.
3. Associated Hardware:
  - a. Insulator:
    - (1) Top groove, porcelain (ceramic), pin type, conforming to ANSI C29.5.
    - (2) Rated for 13.2 / 7.62 kV operation.
  - b. Insulator Pin - bolt:
    - (1) Bolt type conforming to EEI Standard TD-17 (without saddle).
    - (2) Measurements: 5/8" x 10-3/4", 1" cast lead pin thread.
  - c. Insulator Pin - screw:
    - (1) Screw type, with thread, conforming to EEI standard TD-17.
    - (2) 1" cast lead pin thread.
  - d. Guy Insulator shall conform to ANSI C29.4 Class 54-3.
  - e. Guy Wire:
    - (1) 16M, 7 strand, Utilities Grade, conforming to ANSI C7.46, ASTM A475.
    - (2) 25 ft. minimum lead with insulator.
  - f. Anchor:
    - (1) 200 square inch expanding type.
    - (2) Buried 6 ft. in ground minimum.
  - g. Anchor Rods:
    - (1) Shall conform to ANSI Standard C135.2.
    - (2) Measurements: 3/4" diameter by 8'-0" minimum.
4. All pole line hardware and connectors shall be utility grade.

5. Substitution of hardware other than that bearing Rural Electric Association or Edison Electrical Institute label is not acceptable.

## **C. Main Disconnect Switch**

### 1. Electrical Requirements

1. The switch rating shall be 14.4 kV, 110 kV BIL Minimum.
2. Minimum ampacity shall be 400 A continuous.
3. Switch shall be able to withstand the full available short circuit fault conditions designated by the Company.
4. The switch shall be capable of opening under full load.
5. Arcing horns or arc interrupters shall be integral to the switch.
6. Manufacturer tested in conformance to ANSI standard C37.34 series and NEMA, UL, etc.
7. Clearances shall be in accordance with Figure 6, Outdoor Electrical Clearances.

### 2. Mechanical Requirements

1. The Switch shall be gang operated, three (3) pole (three phase) or two (2) pole (single phase L-L) or one (1) pole (single phase L-N), single throw type, complete with operating assembly.
2. The switch shall have a steel frame, suitable for horizontal mounting on a single wood pole.
3. The switch frame shall be capable of supporting a dead-end load of 2000 pounds per conductor for all phases.
4. The Customer shall provide a cable to flat terminal connectors to connect the Company's line to the switch.
5. The switch shall be capable of opening under 1/2" ice loading conditions, NESC "Heavy."
6. The switch shall be mounted so that the handle will be approximately 3'-6" above grade.
7. A 15" insulated outrigger will be required on the load side of the switch.

### 3. Identification Requirements

1. The switch nameplate shall show: nominal voltage, maximum voltage, BIL, continuous, momentary and interrupting amperes.
2. The switch nameplate shall include reference to certifications, i.e., ANSI, NEMA, UL, etc.
3. The switch nameplate shall be mounted on the switch and also near the operating handle.

### 4. Installation Requirements

1. After installation and before being energized, the switch must be thoroughly operationally tested in accordance with the manufacturer's instructions.
2. It is recommended after installation that the switch be maintained in accordance with ANSI C37.35.

## **D. Lightning Arresters**

1. Lightning arresters shall be mounted with an EEI-NEMA TDJ-19 standard bracket.

2. Arrester rating is determined by primary service voltage.

**LIGHTNING ARRESTER RATINGS**

<u>Primary Service Voltage</u>	<u>Arrester Rating (ANSI C62.1)</u>	<u>Max. Continuous Operating Voltage (MCOV)</u>
4.16 kV Wye-Grounded	3 kV	2.55 kV
4.8 kV Delta	6 kV	5.1 kV
13.2 kV Wye-Grounded	10 kV	8.4 kV

**E. Fuses & Fuse Cutouts**

1. For systems operating with a primary voltage of 2.4, 4.16 or 4.8 kV, the fuse cutout value shall be 200 Amp., 5.2 kV, extra heavy duty, extra large bodied indicating cutout, with fuse size as required by ANSI C37.41.
2. For systems operating with a primary voltage of 13.2 kV, the fuse cutout value shall be 100 Amp, 15 kV extra heavy duty, open type with fuse size as required by ANSI C37.41.
3. The magnitude of fault current will be specified by the Company.
4. The fuse size will be specified by the Company.
5. Fuses shall be mounted in porcelain-enclosed or open-type cutouts.
6. The Customer should maintain a stock of four (4) spare fuses to be stored in a convenient dry place.
7. If the Customer uses a circuit breaker or high voltage interrupter in lieu of fuses for main overcurrent protection, refer to ESB #752 for requirements.

**F. Operation and Maintenance Requirements**

The following is in the mutual interest of the Company and the Customer where the Customer's service equipment is directly involved with the Company's System.

**1. General Requirements**

- a. The switching protocol procedure for the mutual interest of the Company and the Customer will be provided by the Company based on the following information from the Customer:
  - Contact personnel and telephone numbers and
  - Single-line diagram from Section I.G above of the Customer's primary and secondary equipment directly involved with the Company's system.
- b. The Customer is responsible for maintaining this information up-to-date and notifying the Company of any changes.
- c. The Customer shall notify the Company whenever switching is performed within the Customer's primary service equipment (i.e., above 2.2 kV and less than 15kV). The Customer is responsible for developing operating instructions for their electrical system.
- d. The Company can provide isolation and grounding guarantees at the Customer's service disconnect or Company isolation point on the supply line ahead of the Customer's service equipment. However, the Customer is responsible for their grounding provisions to work on their de-energized equipment.
- e. The Customer shall operate within established Company mark up rules in any switching operations with the Company for their equipment that both the Company and the Customer have a mutual interest. It is expected the Customer will provide a

qualified person as defined in the National Electrical Code and any other applicable codes.

- f. The Customer must recognize and abide by the Company's mark up rules. The Customer shall conduct their switching based on their switching practices insuring that the Company's mark up is not jeopardized or modified.
- g. References to minimum customer requirements for maintenance, operating, and safety of their high voltage installation include but are not limited to:
  - NFPA 70B "Recommended Practice for Electrical Equipment Maintenance"
  - NETA-MTS "Maintenance Testing Specifications for Electrical Power Distribution Equipment and Systems"
  - NFPA 70E "Electrical Safety Requirements for Employee Workplaces"
  - IEEE/ANSI C2 "National Electrical Safety Code"
  - OSHA 29 CFR 1910.269

## 2. Specific Requirements

- a. Service Personnel and Safety:
  - The Customer is responsible for performing all switching and O&M functions for their equipment.
  - The Customer shall arrange to have qualified personnel available at all times for the proper and safe operation of their equipment.
  - "Qualified Personnel" training shall cover correct operating and safety procedures including, but not limited to:
    - distinguishing exposed live parts,
    - determining the nominal voltage of exposed live parts,
    - determining of the minimum approach distance, and
    - the use of precautionary techniques, personal protective equipment, insulating and shielding materials, and insulated tools for working on or near exposed live parts of electrical equipment.
- b. The Company does not provide any operating tools for the Customer's use. The Customer shall provide their own operating equipment such as tongs, insulating switching sticks, insulated rubber gloves, grounds, ground bails, studs and grounding sticks; voltage detection equipment, etc. needed for the safe performance of operating functions. This operating equipment shall be properly maintained and tested according to the manufacturer's instructions.
- c. Line terminations and the metering transformer compartments of the Customer's switchgear will be locked by the Company when the Company's work is completed and marked clear with the Controller.

## 3. Switching

- a. All switching or other work on high voltage circuits shall be performed by qualified personnel fully equipped with safety equipment tested for the circuit voltage involved.
- b. All Company directed switching within the Customer's primary meter pole service shall be done in accordance with Company-provided switching instructions.
- c. The Company will provide nomenclature for Customer's labeling of the main disconnect switch and other electrical equipment referred to in the Company's switching instructions. The Customer shall make provisions for the labeling of this equipment and any necessary mark-up tag holder.

- d. Tags shall be used to prohibit operation of electrical devices and shall indicate that employees are at work. Equipment shall be locked and rendered inoperable by locking and tagging unless its design does not so permit. Tags alone may be used when the equipment can not be rendered inoperable by locking.
- e. NO WORK SHALL BE DONE ON AN AIR BREAK SWITCH WHILE THE INCOMING LINE IS ENERGIZED.
  - (1) Notify the Company and arrange for an interruption and a guarantee before doing any work at or near this section. Also, if requested, a grounding guarantee may also be provided.
  - (2) THE MAIN DISCONNECTING SWITCH SHALL BE LOCKED OPEN PRIOR TO CHANGING FUSES OR WORKING ON HIGH VOLTAGE EQUIPMENT.
  - (3) THE SAFETY PRECAUTIONS outlined in the NESC ANSI C2, OSHA and local requirements shall be strictly adhered to. The Customer shall ensure the circuit/equipment has been tested as deenergized and grounded prior to work.

4. Maintenance

- a. The Customer is responsible for maintaining all equipment under their ownership.
- b. Proper preventative maintenance is important to the operation of the equipment and shall be performed.
- c. NFPA Standard No. 70B on "Electrical Equipment Maintenance" and NETA-MTS "Maintenance Testing Specifications for Electrical Power Distribution Equipment and Systems" are two publications that could be helpful in setting up a dynamic maintenance program. Copies of test records of major station equipment and protective devices that both the Company and the Customer have a mutual interest in shall be maintained on the premise and be made available to the Company upon request, e.g. breaker, transformer, outdoor switches, and relay devices.
- d. The Company does not provide any spare parts for the Customer's installation. The Customer should determine their inventory of spare parts for circuit breakers, fault interrupters, switchgear, and other electrical equipment essential to minimize their interruption time.
- e. Customer access to Company controlled electrical spaces within Customer-owned electric facilities:

The Company's control of electric spaces in Customer-owned electric facilities is for the sole purpose of protecting the integrity of the Company's energy supply and security of the utility metering equipment. Any costs shall be determined by the Company's filed tariff. In these requirements, "Customer" refers to the Customer or their agent. Under this and all other policies, it is expected and it is the Customer's responsibility to provide a qualified person as defined in the National Electrical Code and any other applicable codes.

- (1) The Company can provide isolation and grounding guarantees at the Customer's service disconnect or Company isolation point on the supply line ahead of the Customer's service equipment. However, the Customer is responsible for their grounding provisions to work on their de-energized equipment.
- (2) When the Customer does not require a guarantee on the supply line and needs access to Company-controlled electrical spaces for their maintenance purposes, the Company in its sole judgment may determine the ability to grant access to the Customer for the duration established by the Company. When granted, the Company will witness the Customer's placement of their lock immediately after the removal of the Company's lock. Upon notification by the Customer that their work is complete, the Customer shall relinquish access back to the Company and

the Company's lock shall be placed immediately upon the removal of the Customer's lock. In each case the transfer shall occur in the presence of both parties. The Company will check it's electrical equipment for any signs of tampering.

In the event that the required access is of short duration and the Company's representative remains on site, to avoid a second trip, it is understood they are doing so without any supervisory or oversight capacity relative to the Customer.

## **VI. GROUNDING**

### **A. Requirements**

1. The group-operated airbreak disconnecting switch mechanism shall be connected to the grounding grid near the operating handle by means of a flexible, tinned copper braid of at least 200 Ampere rating.
2. Bond all non-current carrying metallic parts on the receiving structure to equipment ground with a stranded #4AWG bare copper conductor.
  - a. This includes switch frame, lightning arresters, guy wires, switch base, and the neutral (where furnished).
  - b. Ground connections shall conform to those on the appropriate schematic diagram, Figure 1 or Figure 2, depending on the type of phase service.
3. At least 2 ground rods shall be used.
4. The ground rods shall be at least 5/8" x 8'-0" with clamps.
5. The down leads to the ground rods shall be affixed to the rods in a manner consistent with Figure 5.
6. The ground rods shall be buried at least 6 inches below grade.
7. The rods shall be spaced at a minimum distance of 3 ft. from the center of the pole, and at least 6 ft. minimum from each other.
8. The ground rods shall be bonded together with #4 AWG bare copper conductor.

### **B. Potential Equalizing Grid**

1. A 5 feet x 6 feet grid of 8 inch x 8 inch copperweld mesh shall be installed below the operating handle to protect servicing personnel.
  - a. The grid and the switch handle's ground strap shall be connected to the pole's grounding conductor.
  - b. The grid shall have 3 inches of #2 crushed stone beneath it.
  - c. The grid is to be laid 3 inches below grade, covered by #2 crushed stone.
  - d. Installation shall conform to Figure 5.

### **C. Safety Precautions**

1. **EVEN WITH THE GROUNDING PROVISIONS SUGGESTED, IT IS IMPERATIVE THAT A PERSON OPERATING GROUP-OPERATED SWITCHES WEAR RUBBER GLOVES.**

## **VII. METERING**

### **A. Company's Responsibility**

1. The Company will specify and provide the metering equipment.
2. The Company will make secondary connections to the meter.

3. The Company will install the meter.

**B. Customer's Responsibility**

1. The Customer will install the metering transformers and mounting frame, and an outdoor metering trough on the primary receiving structure in a manner consistent with Figures 1, 3 and 3A or Figures 2 and 4, depending on the type of phase service.
2. The Customer will make primary connections to the Company's metering transformers.

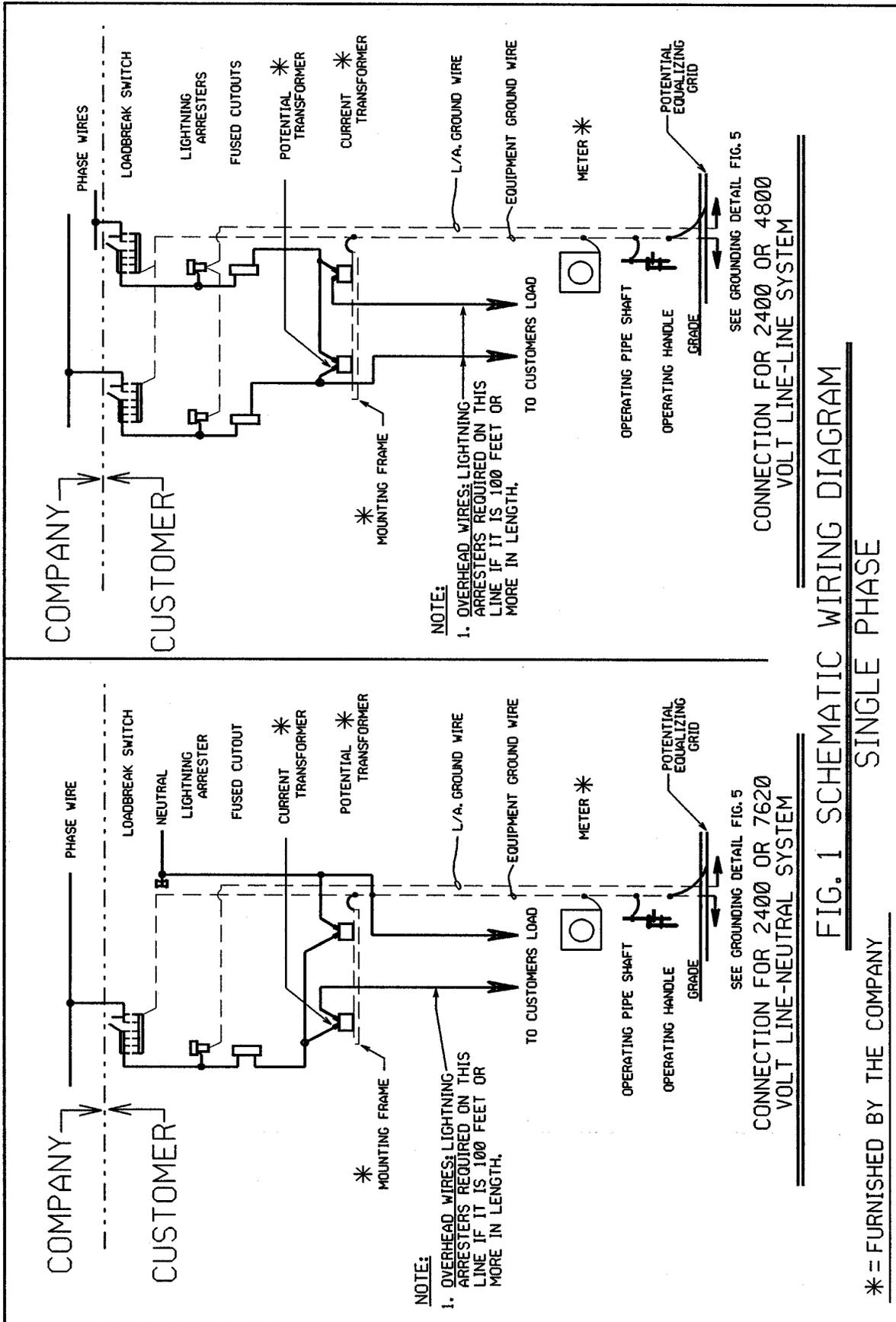


FIG. 1 SCHEMATIC WIRING DIAGRAM  
 SINGLE PHASE

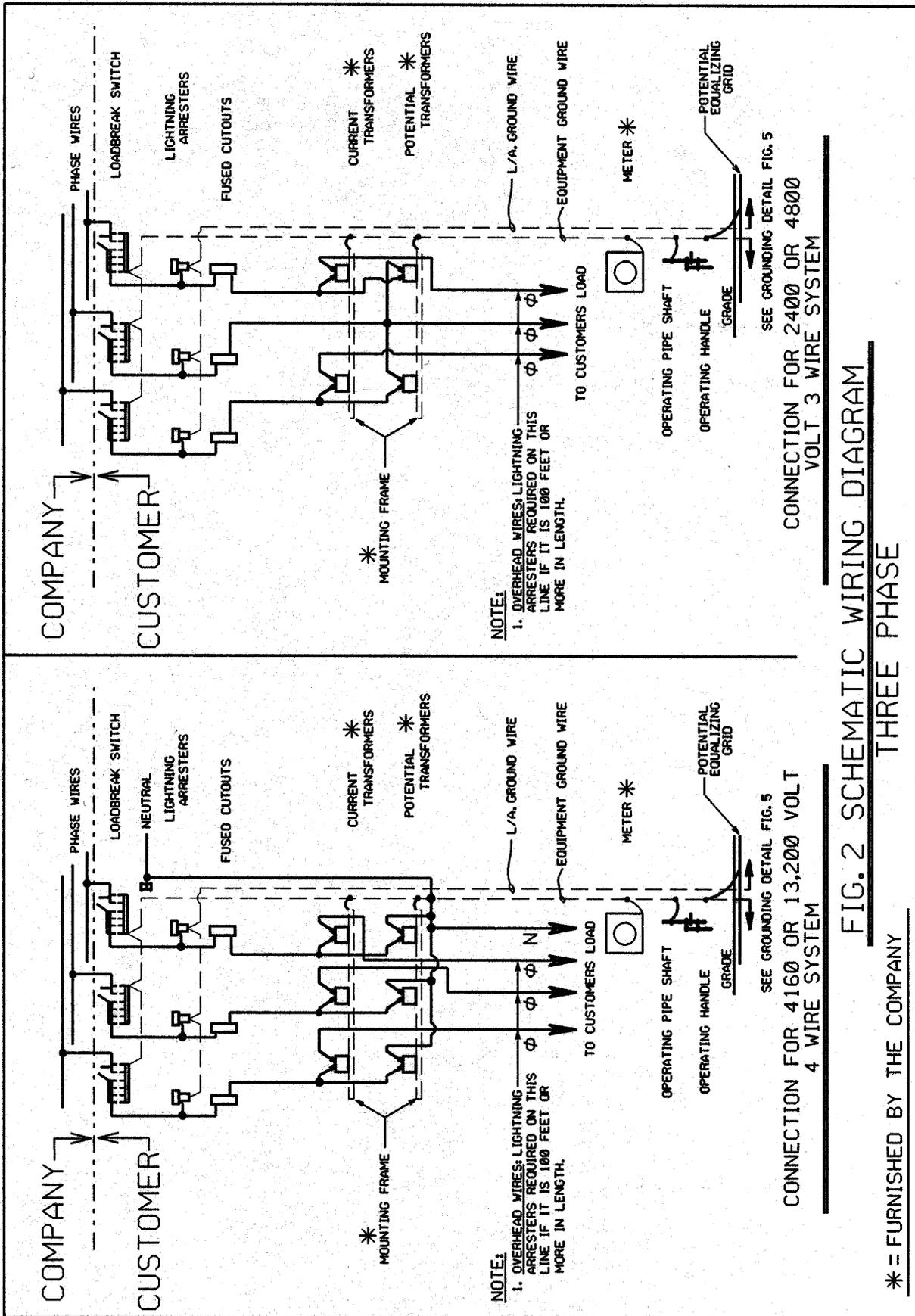
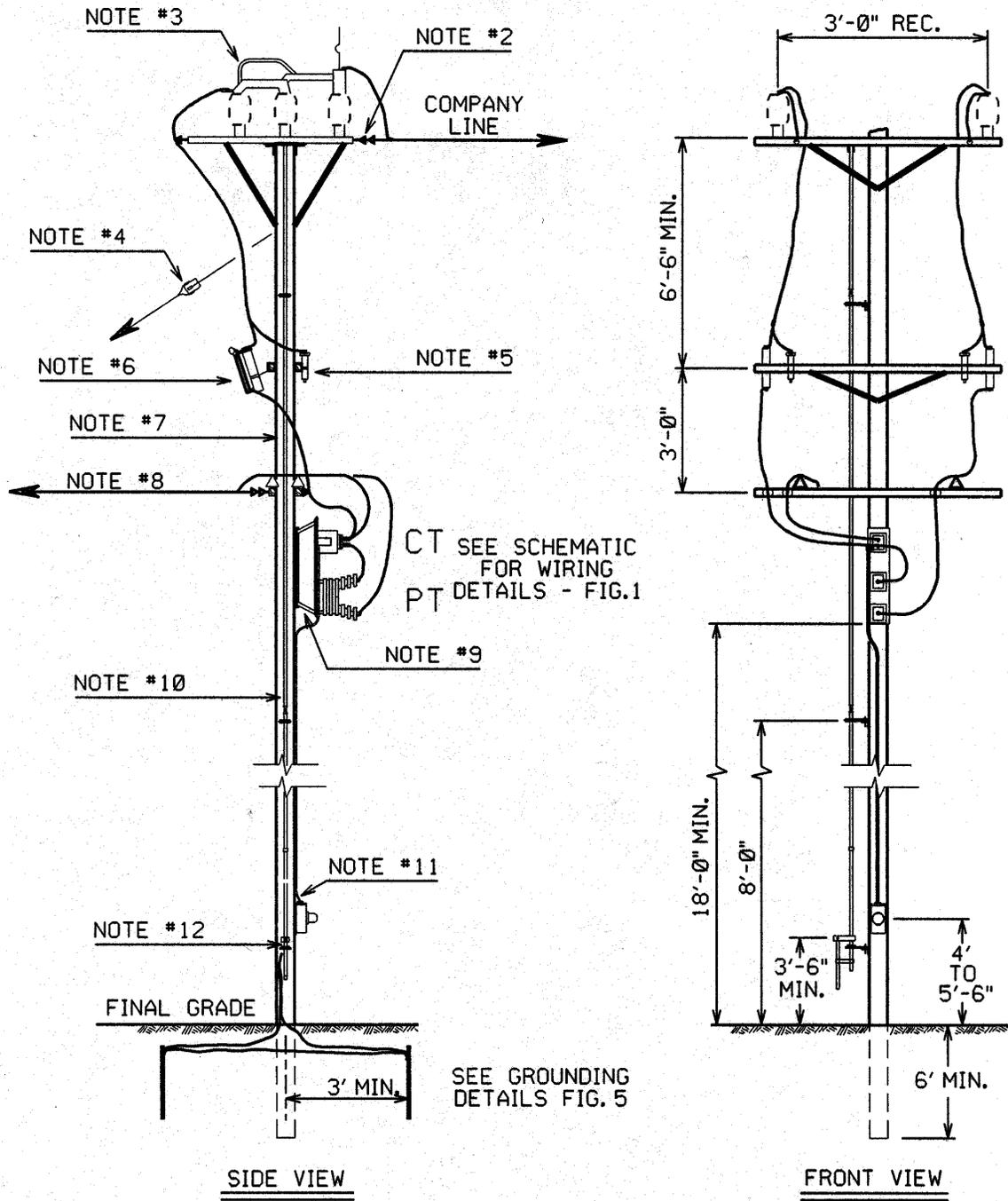


FIG. 2 SCHEMATIC WIRING DIAGRAM  
 THREE PHASE

\* = FURNISHED BY THE COMPANY

### FIGURE 3 - NOTES

1. CUSTOMER TO FURNISH, INSTALL, OWN AND MAINTAIN EVERYTHING SHOWN EXCEPT AS NOTED.
2. DEAD END INSULATOR, CLAMPS AND CLEVISES FURNISHED AND INSTALLED BY COMPANY.
3. COMPANY APPROVED 2 P.S.T. GROUP OPERATED 14.4 kV, 400 AMP LOADBREAK SWITCH WITH WOOD POLE STEEL MTG. FRAME SUITABLE FOR SUPPORTING LINE TENSIONS OF 2000 LBS. PER CONDUCTOR AT 3 FT. PHASE SPACING COMPLETE WITH 1-1/2" SHAFT ASSEMBLY. 15 INCH OUTRIGGER REQUIRED. PROVIDE TERMINALS TO FIT COMPANY INCOMING LINE.
4. GUY TO ANCHOR BURIED 6 FT. IN GROUND, 25 FT. MIN. LEAD WITH INSULATOR.
5. LIGHTNING ARRESTERS. USE SEPARATE GROUNDING CONDUCTOR TO GROUND GRID.
6. FUSED CUTOUPS - FUSE SIZE TO BE SPECIFIED BY THE COMPANY.
7. #4 AWG BARE COPPER GROUNDING CONDUCTOR. BOND ALL METALLIC NON-CURRENT CARRYING PARTS TO THE EQUIPMENT GROUND WIRE.
8. TO CUSTOMER'S LOAD. CONDUCTOR CLEARANCE 22 FT. MINIMUM AT MID SPAN.
9. MOUNTING FRAME AND METERING TRANSFORMERS FURNISHED BY COMPANY, INSTALLED BY CUSTOMER. PRIMARY CONNECTIONS MADE BY CUSTOMER, SECONDARY CONNECTIONS BY COMPANY.
10. OPERATING SHAFT (REFER TO DETAIL IN FIG. #5.)
11. 1-1/2" RIGID METALLIC OR SCHEDULE 80 P.V.C. CONDUIT INSTALLED BY CUSTOMER.
12. INSTALL BRACKET SO THAT OPERATING HANDLE WILL BE APPROX. 3'-6" ABOVE GRADE.



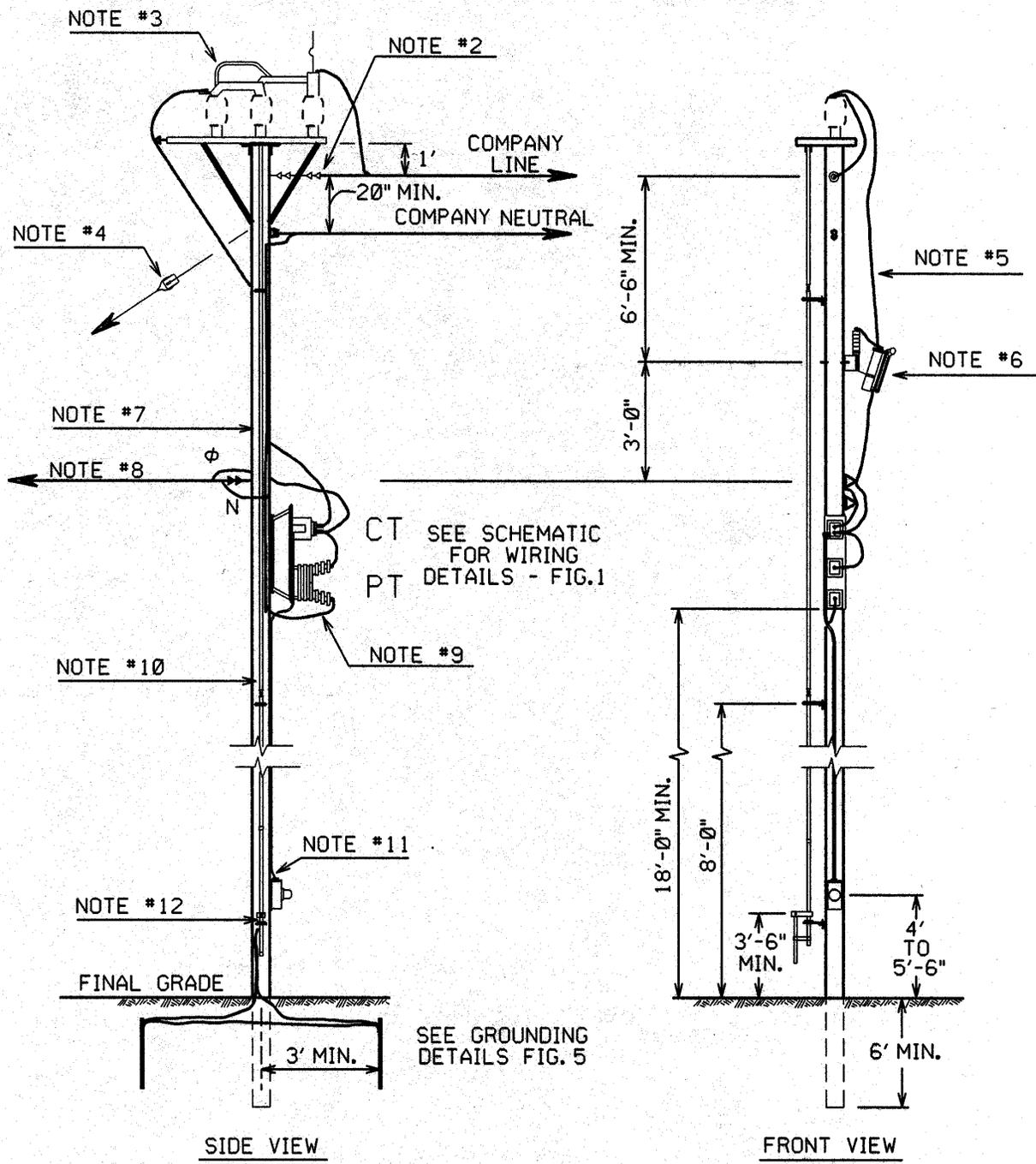
SEE GROUNDING  
 DETAILS FIG. 5

2,400 - 4,800 VOLT LINE-LINE  
SINGLE PHASE

**FIGURE NO. 3**  
**CUSTOMER'S OUTDOOR RECEIVING STRUCTURE ARRANGEMENT**  
**SINGLE-PHASE-100KVA LIMITATION**

## FIGURE 3A - NOTES

1. CUSTOMER TO FURNISH, INSTALL, OWN AND MAINTAIN EVERYTHING SHOWN EXCEPT AS NOTED. POLE TO BE SUITABLE FOR SUPPORTING LINE TENSION OF 2000 LBS. AT COMPANY'S LINE ATTACHMENT HEIGHT.
2. DEAD END INSULATOR, CLAMPS AND CLEVISES FURNISHED AND INSTALLED BY COMPANY.
3. COMPANY APPROVED 1 P.S.T. MANUALLY OPERATED 14.4 kV, 400 AMP LOADBREAK SWITCH WITH STEEL BASE. SWITCH SHALL HAVE 1-1/2" SHAFT ASSEMBLY AND 15 INCH OUTRIGGER. PROVIDE TERMINALS TO FIT COMPANY INCOMING LINE.
4. GUY TO ANCHOR BURIED 6 FT. IN GROUND, 25 FT. MIN. LEAD WITH INSULATOR.
5. LIGHTNING ARRESTER. USE SEPARATE GROUNDING CONDUCTOR TO GROUND GRID.
6. FUSED CUTOUT - FUSE SIZE TO BE SPECIFIED BY THE COMPANY.
7. #4 AWG BARE COPPER GROUNDING CONDUCTOR. BOND ALL METALLIC NON-CURRENT CARRYING PARTS TO THE EQUIPMENT GROUND WIRE.
8. TO CUSTOMER'S LOAD. CONDUCTOR CLEARANCE 22 FT. MINIMUM AT MID SPAN.
9. MOUNTING FRAME AND METERING TRANSFORMERS FURNISHED BY COMPANY, INSTALLED BY CUSTOMER. PRIMARY CONNECTIONS MADE BY CUSTOMER, SECONDARY CONNECTIONS BY COMPANY.
10. OPERATING SHAFT (REFER TO DETAIL IN FIG. #5.)
11. 1-1/2" RIGID METALLIC OR SCHEDULE 80 P.V.C. CONDUIT INSTALLED BY CUSTOMER.
12. INSTALL BRACKET SO THAT OPERATING HANDLE WILL BE APPROX. 3'-6" ABOVE GRADE.

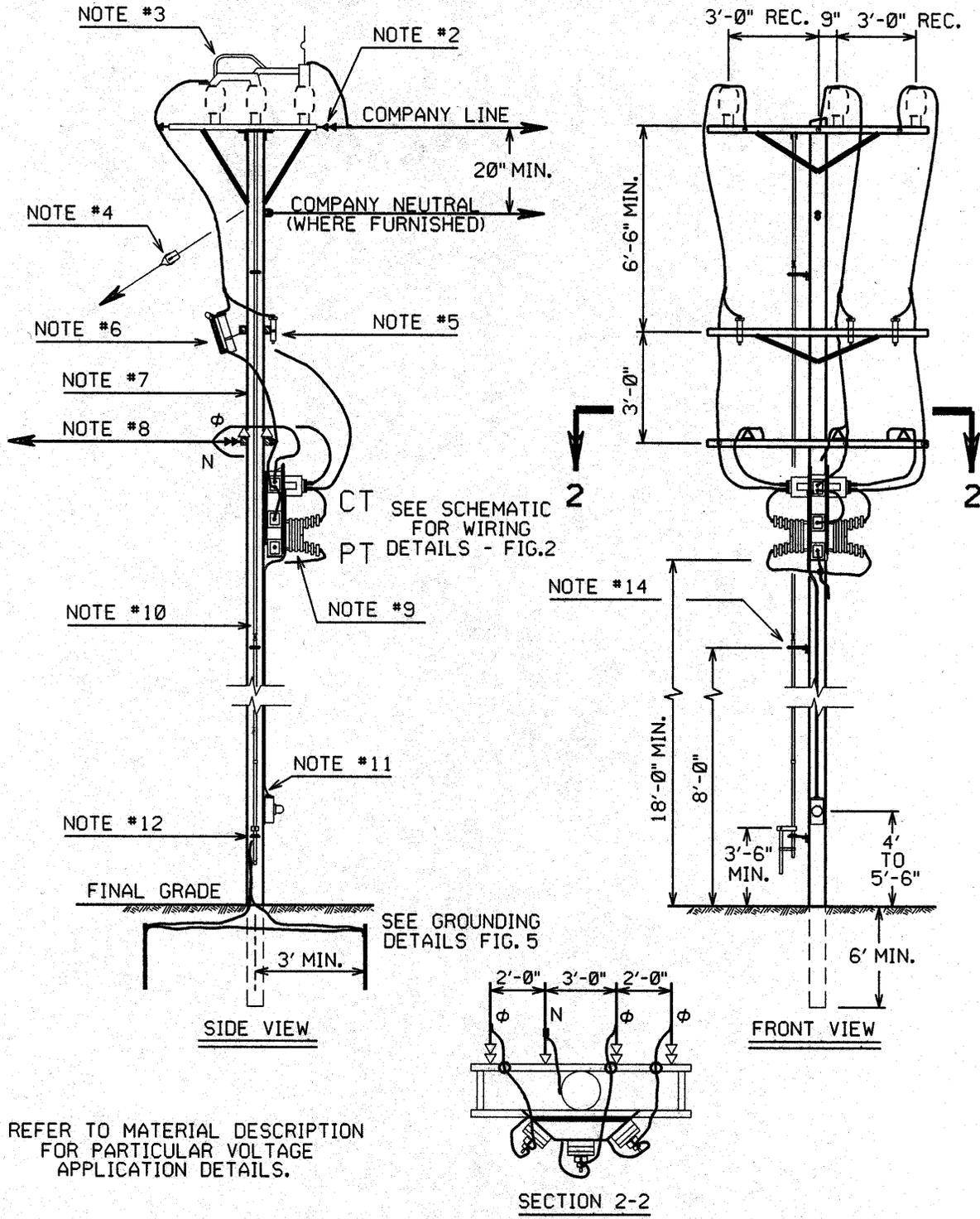


2,400 - 7,620 VOLT LINE-NEUTRAL  
SINGLE PHASE

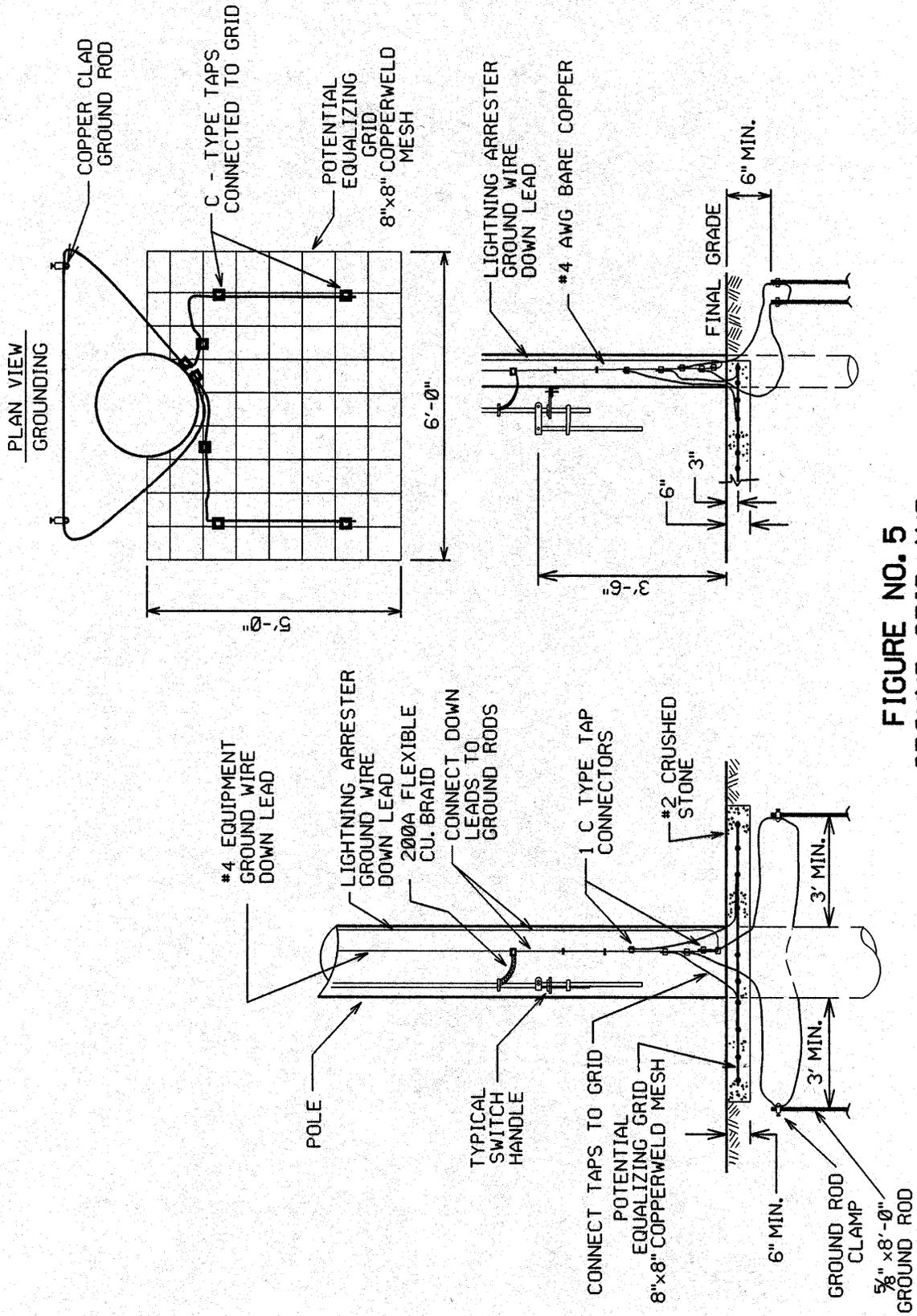
**FIGURE NO. 3A**  
**CUSTOMER'S OUTDOOR RECEIVING STRUCTURE ARRANGEMENT**  
**SINGLE-PHASE-100KVA LIMITATION**

## FIGURE 4 - NOTES

1. CUSTOMER TO FURNISH, INSTALL, OWN AND MAINTAIN EVERYTHING SHOWN EXCEPT AS NOTED.
2. DEAD END INSULATOR, CLAMPS AND CLEAVES FURNISHED AND INSTALLED BY COMPANY.
3. COMPANY APPROVED 3 P.S.T. GROUP OPERATED 14.4 kV, 400 AMP LOADBREAK SWITCH WITH WOOD POLE STEEL MTG. FRAME SUITABLE FOR SUPPORTING LINE TENSIONS OF 2000 LBS. PER CONDUCTOR AT 3 FT. PHASE SPACING COMPLETE WITH 1-1/2" SHAFT ASSEMBLY. 15 INCH OUTRIGGER REQUIRED. PROVIDE TERMINALS TO FIT COMPANY INCOMING LINE.
4. GUY TO ANCHOR BURIED 6 FT. IN GROUND, 25 FT. MIN. LEAD WITH INSULATOR.
5. LIGHTNING ARRESTERS. USE SEPARATE GROUNDING CONDUCTOR TO GROUND GRID.
6. FUSED CUTOUPS - FUSE SIZE TO BE SPECIFIED BY THE COMPANY.
7. #4 AWG BARE COPPER GROUNDING CONDUCTOR. BOND ALL METALLIC NON-CURRENT CARRYING PARTS AND THE NEUTRAL (WHERE FURNISHED) TO THE EQUIPMENT GROUND WIRE.
8. TO CUSTOMER'S LOAD. CONDUCTOR CLEARANCE 22 FT. MINIMUM AT MID SPAN.
9. MOUNTING FRAME AND METERING TRANSFORMERS FURNISHED BY COMPANY, INSTALLED BY CUSTOMER. PRIMARY CONNECTIONS MADE BY CUSTOMER, SECONDARY CONNECTIONS BY COMPANY.
10. OPERATING SHAFT (REFER TO DETAIL IN FIG. #5.)
11. 1-1/2" RIGID METALLIC OR SCHEDULE 80 P.V.C. CONDUIT INSTALLED BY CUSTOMER.
12. INSTALL BRACKET SO THAT OPERATING HANDLE WILL BE APPROX. 3'-6" ABOVE GRADE.



**FIGURE NO. 4**  
**CUSTOMER'S OUTDOOR RECEIVING STRUCTURE ARRANGEMENT**  
**THREE-PHASE**



**FIGURE NO. 5  
 GROUND GRID AND  
 SWITCH HANDLE GROUNDING**

<b>Preferred Nominal System Voltage</b>	2400V 4160V 4800V 7200V 4.8/8.32kV 7.62/13.2kV	12kV  13.2kV
	<b>BIL</b>	<b>110kV</b>
	<b>Max. kV Rating</b>	<b>15.5</b>
Centerline-to-Centerline Spacing of Buses	18"	2'-0"
Clearance Between Live Parts	<b>Recommended</b> 12" <b>Minimum</b> 7"	18" 12"
Clearance from Live Parts to Ground	<b>Recommended</b> 8" <b>Minimum</b> 6"	10" 7"
<b>Min.</b> Clearance to Unguarded Live Parts for Personnel On Foot	<b>Vertical</b> 9'-0" <b>Horizontal</b> 3'-4"	9'-6" 3'-6"
<b>Min.</b> Spacing of Horn Gap Switches	<b>Phase-to-Phase</b> 18"	2'-0"
<b>With</b> Arc Extinguishing Device	<b>Phase-to-Ground</b> 8"	10"
<b>Min.</b> Spacing of Horn Gap Switches	<b>Phase-to-Phase</b> 3'-0"	3'-0"
<b>Without</b> Arc Extinguishing Device	<b>Phase-to-Ground</b> 2'-0"	2'-0"
<b>Minimum</b> Vertical Clearance to Unguarded Live Parts for Vehicular Traffic	22'-0"	
<b>Min. Safety Clearance</b> to Nearby Structures	10'-0"	10'-2"

## OUTDOOR ELECTRICAL CLEARANCES - FIGURE 6

**SUPPLEMENT TO  
SPECIFICATIONS FOR  
ELECTRICAL INSTALLATIONS**

**OUTDOOR PADMOUNTED  
OR VAULT ENCLOSED  
THREE PHASE TRANSFORMER**

**ELECTRIC SYSTEM BULLETIN No. 754/759**

**October 2007**

(Supersedes issue dated December 2004.)

**nationalgrid**

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## 1.0 INTRODUCTION

### 1.1 Purpose

This Supplement to Electric System Bulletin (ESB) #750 provides specific guidance for Customers whose service point is the secondary side of a Company owned transformer located on Customer owned or controlled property.

This supplement applies where the Company's underground service lateral cable taps a primary distribution or sub-transmission supply facility (that can be either overhead or underground in nature) to feed a Company owned outdoor three phase pad-mounted transformer, or transformer(s) located within a vault. It does not apply in a network area, or in URD / UCD areas.

These requirements are to ensure that the electric facilities will render satisfactory service to the Customer, and will not interfere with the electric supply to others served by the Company's system.

It is important that the Customer and their engineer or contractor obtain and refer to the Specifications for Electrical Installations book (ESB #750) in conjunction with this supplement for these installations.

Installations requiring dual supplies, switching and protection at the transformer, dual primary voltage transformer, or multiple transformers shall be referred to the Company's Engineering Department for specific recommendations and approval.

In response to the Customer's written proposal, the Company will make the final determination as to the size, type, and location of the transformer used to provide service under this bulletin.

### 1.2 Scope

These requirements concern only those points in which the Customer, their Consulting Engineer, Electrical Contractor, Equipment Manufacturer, and the Company have a mutual interest. This bulletin does not cover the Customer's complete electrical installation design.

#### 1.2.1 Provisions

The installation provisions and costs shall be in accordance with the Company's filed tariffs in the applicable State.

State	Company furnishes, installs, owns and provides maintenance for:	Customer furnishes, installs, owns and provides maintenance for:
MA & RI	<ul style="list-style-type: none"> <li>• an outdoor padmounted transformer</li> <li>• primary cable</li> </ul>	<ul style="list-style-type: none"> <li>• property on which to construct the transformer foundation</li> <li>• transformer pad foundation</li> <li>• ground grid</li> <li>• primary cable trench</li> <li>• outdoor padmounted transformer foundation excavation</li> <li>• where required, the primary conduit system* [it is recommended that spare conduit be installed]</li> <li>• backfill all trenching and excavations after primary cable installation</li> <li>• bollards, if required by the Company</li> </ul>
NH	<ul style="list-style-type: none"> <li>• an outdoor padmounted</li> </ul>	<ul style="list-style-type: none"> <li>• property on which to construct the transformer</li> </ul>

State	Company furnishes, installs, owns and provides maintenance for:	Customer furnishes, installs, owns and provides maintenance for:
	transformer	<ul style="list-style-type: none"> <li>foundation</li> <li>• primary cable trench</li> <li>• primary cable</li> <li>• outdoor padmounted transformer foundation excavation</li> <li>• transformer pad foundation</li> <li>• ground grid</li> <li>• where required, the primary conduit system [it is recommended that spare conduit be installed]</li> <li>• backfill all trenching and excavations after primary cable installation</li> <li>• bollards, if required by the Company</li> </ul>
NY	<ul style="list-style-type: none"> <li>• an outdoor padmounted transformer</li> <li>• primary cable and terminations</li> </ul>	<ul style="list-style-type: none"> <li>• property on which to construct the transformer foundation</li> <li>• primary cable trench</li> <li>• outdoor padmounted transformer foundation excavation</li> <li>• transformer pad foundation</li> <li>• ground grid</li> <li>• where required, the primary conduit system [it is recommended that spare conduit be installed]</li> <li>• backfill all trenching and excavations after primary cable installation</li> <li>• bollards, if required by the Company</li> </ul>

\* Ownership transfer to Company after initial installation for operation and maintenance.

### 1.2.2 Additional Customer Provisions

The Customer shall furnish, install, own, and maintain the complete low voltage service connection from the transformer low voltage terminals, including conduit, cables, compression connectors, etc.

## 1.3 Codes and Standards

The Customer's electric service equipment and its installation shall conform to the requirements of the latest edition of the National Electrical Code (NEC), American National Standards Institute (ANSI), Insulated Cable Engineers Association (ICEA), National Electrical Manufacturer's Association (NEMA), National Fire Protection Association (NFPA), all local ordinances, state and local building codes and Company requirements and specifications.

The Customer should consult their insurance carrier for any special safeguards which the carrier may require for the transformer and switchgear locations.

## 1.4 Compliance

### 1.4.1 Preliminary Design

Prior to meeting with the Company, the Customer shall provide three (3) copies of an electrical single-line diagram and a fully dimensioned plot plan indicating property lines, building outlines and detail of the preferred location for the electrical service equipment, transformer pad or vault, as well as the location of other buried facilities.

For a specific installation it is essential the Company meet with the Customer or their representative to mutually establish the arrangement and location of the proposed facilities.

As a result of this meeting, the Company will confirm the delivery voltage, specify the transformer size and type based on the amount of capacity the Customer is currently requesting. In addition the Company will provide the short circuit interrupting duty that the Customer's equipment shall be capable of interrupting based on Section 9 in ESB 750. The Customer is responsible to ensure their service equipment will be satisfactory for the supply characteristics in accordance with the NEC and sufficient for their future maximum demand.

The information the Customers or their contractor furnishes the Company in regard to the Customer's proposed electrical installation shall be in **writing**.

If significant changes are made to the design or scheduling of the installation by the Customer, initial information furnished by the Company shall be subject to review and possible modification.

**1.4.2 Construction Design**

After the initial meeting, the Company will designate the pole, manhole, or switchgear from which the primary cable will be extended including the route of the primary cable and locations of handholes and manholes.

The Company's Business Services or Distribution Design Department will advise the Customer concerning any contribution required in accordance with the Company's filed tariff.

**THE CUSTOMER SHALL SUBMIT THEIR FINAL PLANS TO THE COMPANY BEFORE AWARDING CONTRACTS, ORDERING EQUIPMENT OR STARTING WORK** to ensure that the proposed design for the electric service installation conforms to Company requirements. Three (3) copies of the following information shall be submitted to the Company for its acceptance:

1. Architectural drawings and specifications relating to the electric service equipment and transformer pad location. Design drawings pertaining to a vault installation shall be uniformly prepared and sealed by the Customer's design professional.
2. Manufacturer's proposed specifications for the electrical service equipment.
3. Manufacturer's approval assembly drawings relating to the physical arrangement of the electrical service equipment including installation details for metering transformers.
4. Electrical single-line diagram illustrating the service connection up to the main service equipment, metering, and any standby generation including transfer equipment.

**2.0 DEFINITIONS**

**Note:** Definitions as used in this specification are provided in the "**Specifications for Electrical Installations**" book (ESB#750).

**3.0 GENERAL**

**3.1 Service Voltage and Maximum Transformer Size:**

<u>Wires</u>	<u>Delivery Voltage</u>	<u>Transformer kVA Limit</u>		
		<u>Outdoor Padmount</u>	<u>Vault (3- 1 ph. transf.)</u>	<u>Vault (padmount)</u>
4	208 wye/120	1000	1000	1000
4	480 wye/277	2500	1500	2500

## 4.0 SERVICE CONNECTIONS

### 4.1 Handholes:

- One or more masonry, or polymer concrete, handholes may be required to facilitate cable pulling or conduit drainage.
- Where splicing is necessary, handholes may be permitted for cables less than #4/0AWG.
- The minimum size of a handhole shall be 2-1/2 feet wide x 5 feet long x 3 feet deep, inside dimensions with a full length, two section split cover. Refer to Figure 10 for typical handhole construction.
- The design of the handhole shall be approved by the Company.
- The top of the handhole cover shall be at finished grade.
- All handholes, including covers, shall be capable of withstanding H-20 loading; however, these are not meant for installation in streets and roadways.
- A pulling eye shall be installed on the short width wall and shall be 1-inch diameter eye bolt. The pulling eye and wall shall be capable of 1,500 pounds pulling strength.
- The handhole floor shall be on a flat, #2 crushed stone base 4 inches thick.
- Conduits shall enter the handhole directly opposite each other on the smaller end walls.
- Conduit bells shall be installed on each conduit.
- The centerline of the conduit in the handhole shall be approximately 6 inches from the 5 foot wall and 15 inches above the floor.
- If metallic conduit is used, a #2 CU ground grid shall be installed to allow for the bonding of the conduit. Conduit shall be bonded together with a #4 Cu (solid) to the ground grid.
- Where splicing is necessary for one set of #4/0AWG cables, a heavy duty handhole may be used per Figure 10. For multiple sets of #4/0AWG cables, or cables larger than #4/0AWG a manhole shall be used.

### 4.2 Manholes:

- One or more masonry or concrete manholes may be required to facilitate cable pulling or conduit drainage.
- The design of the manhole shall be approved by the Company; refer to Figure 11 for specifications.
- All manholes shall have a 26-inch manhole cover with a 36-inch minimum cast iron frame, designed for AASHO-HS20-44 direct wheel loading and 26-inch to 36-inch manhole ring as indicated in Figure 11.
- The top of the manhole cover shall be at finished grade.
- All manholes, including covers, shall be capable of withstanding AASHO-HS20-44 direct wheel loading.
- A 4/0 AWG, 19 strand soft drawn ground grid shall be installed in the manhole.
- If metallic conduit is used, conduit shall be bonded together with a #4 Cu (solid) to the ground grid

### 4.3 Primary Riser Pole:

The Customer shall install a rigid galvanized steel conduit and a rigid galvanized steel sweep on the Company’s primary cable riser pole. For riser conduit installation details, see Figure 12 of this bulletin and refer to Section 4.3.2 and Table 5 “Primary Conduit Sizes” of ESB 750.

### 4.4 Customer's Secondary Conduit and Cable System

#### 4.4.1 Padmounted Transformer

- Customer’s conduits shall be terminated at the equipment pad at the locations shown in Figure 6.
- The Company's transformer will be equipped with bushings that accept NEMA standard two-hole spade terminals mounted in the secondary compartment.
- Size and number of customer’s secondary cables (service entrance conductors) shall be in accordance with the NEC and shall be approved by the Authority Having Jurisdiction (AHJ).
- The Customer-owned secondary conductors shall be insulated, stranded cable up to the maximum number listed below (number of conductors/phase and neutral):

Transformer 75°C Spade Terminal	Transformer Application		Maximum Secondary Conductor Sets and Size
	kVA Rating	L.V. Rating	
4 Hole Spades	75 – 300	208Y/120	6 sets 750 kcmil
	75 – 500	480Y/277	
6 Hole Spades	500	208Y/120	8 sets 750 kcmil
	750 – 1500	480Y/277	
10 Hole Spades	750 – 1000	208Y/120	10 sets 600 kcmil or 8 sets of 750 kcmil
	2000 – 2500	480Y/277	

Details of the Company’s transformer spade terminals are shown in Figure 9.

- If a Customer requires more cables or the total circuit exposure exceeds 1000 feet, the Customer shall provide suitable service equipment adjacent to the padmount transformer.
  1. This equipment shall consist of an outdoor cubicle with bus of a capacity to meet the transformer load and braced for the short circuit capacity.
  2. Each cable leaving this device shall have overcurrent protection.
  3. The service equipment shall be approved by the Company prior to fabrication.
- The neutral bushing of the transformer shall be connected by the Customer with full size neutral conductor(s) and grounded to the pad ground.

#### 4.4.2 Vault Transformer – Utilizing Single Phase Transformers

- Bus duct is recommended for the connection between the transformer secondary terminals in the vault and the service equipment in the electric room. The bus duct enclosure shall be electrically continuous to the service equipment enclosure.
- The leads which connect the secondary bus to the transformer terminals shall be insulated stranded copper cable not smaller than the size listed in the National Electrical Code for “Single conductor in free air” for the current to be conducted when the transformer is carrying its rated kVA load.
- The neutral bushing of each transformer within a vault shall be connected by the Customer with a full size neutral conductor(s) external of the bus duct and grounded to the vault ground.

#### 4.4.3 Terminations for padmount and single phase transformers

- All secondary connectors and connector fasteners shall be furnished, installed, owned and maintained by the Customer.
- Secondary connectors shall be listed for the purpose according to the NEC and meet the Company's requirements in Section 4.4.1 above and as follows.
  1. Minimum secondary conductor connector thickness shall be ¼ inch, with 9/16 inch diameter holes. Aluminum connectors shall be used with aluminum cable and bronze connectors shall be used with copper cable. Tin plated connectors can also be used as an alternate for aluminum and bronze connectors.
  2. Connector shall be a cable to flat clamp or compression type connector, with a minimum of two holes in the flat pad and two clamping elements or two compressions per cable.
- Secondary connector fasteners for use at the transformer terminals shall be stainless steel and listed for the purpose according to the NEC.
- Final torque tightening of the secondary connectors shall be completed by the customer.
- The Customer shall provide the Company with a written report of satisfactory installation acceptance tests of their service cables and connections to the secondary terminals of the Company's transformer prior to energization. See Checklists in Figure 14.
- The exposed live parts of the secondary connections may be required to be covered with electrical tape (or equivalent), by the customer, if deemed necessary by the company, to a thickness not less than 1/16 inch, where between live parts and live part-to-ground spacing has been compromised.

## 5.0 TRANSFORMER INSTALLATIONS ON CUSTOMER PREMISES [Excluding Underground Residential/Commercial Distribution (URD/UCD)]

### 5.1 Padmount Transformer Location

#### General:

- The Company will endeavor to work with the Customer to determine a mutually satisfactory location of the Company's transformer; however, the final location of the transformer shall be at the sole discretion of the Company.
- Where sufficient property exists, space separation shall always be used as the primary safeguard method to comply with **Rule 152A** of the **NESC** regarding the requirements of outdoor installed liquid-filled transformers. In no instance, will the Company rely on automatic extinguishing systems for installations on private property.
- As the Company's service point is the secondary terminals of the transformer, the transformer should be located as close as possible to the Customer's load center.

#### Proximity to Buildings:

The clearances to buildings and property lines shown in Figure 2 are chosen to achieve the necessary space separations for oil-insulated transformers installed outdoors in accordance with good utility practice. Where these space separations can not be achieved, additional safeguard methods such as oil containment and absorption systems, fire-resistant barriers, etc. may be considered by the Company if first approved in writing by the appropriate local authority having jurisdiction over fire prevention. In extreme cases, the transformer may need to be installed in a vault. To ensure the Company has adequate access to the transformer, under no circumstances will clearances be reduced to less than five (5) feet from the edge of the transformer pad or three (3) feet from the inside edge of the transformer

oil containment curb where used to the sides of the transformer. The minimum distance for the front of the transformer must be at least 10 feet.

- Clearances shall be measured from inside edge of transformer oil containment curb where oil containment is required.
- If the building has an overhang the distance to the inner edge of the transformer oil containment shall be measured horizontally from the outer edge of the overhang.

#### **Proximity to Above Grade Facilities:**

A horizontal clearance measuring ten (10) feet from the edge of the transformer pad shall be maintained to the closest point of all fire hydrants, cell towers, or other foreign objects.

A horizontal clearance measuring twenty-five (25) feet from the edge of the transformer pad or the inner edge of the transformer oil containment where used shall be maintained to the closest point of all above grade gas piping, fuel lines, and fuel storage tanks. Where this clearance can not be achieved, an additional safeguard such as a fire-resistant barrier shall be necessary and be approved in writing by the Fire Protection Code AHJ and shall not be less than five (5) feet from the edge of the transformer pad.

#### **Proximity to Buried Facilities:**

An area measuring ten (10) feet from the edge of the transformer pad or each inner edge of the transformer oil containment where used shall be maintained to the closest point of all buried waterlines, gas lines, sewer lines, communications circuits, other electric lines, storage tanks, etc.

#### **Vehicular Traffic:**

The Company will determine when bollards are required to protect transformer installations that may be exposed to vehicular traffic, grass cutting, or snow plowing equipment.

Any bollards that are required shall be provided and installed by the Customer as specified in Figure 2.

#### **Transformer Oil:**

Transformer installations on premises are subject to Company, local, state, and federal environmental rules and regulations. Where the Customer chooses or if the transformer location is near an environmentally protected area or there is risk of fire spread in space limited locations the transformer shall have oil spill containment. See Figure 4 for oil spill containment construction and spacing requirements. The following are considerations for when oil spill containment is necessary:

- Project location in National or State parks.
- Environmental resources or sensitive areas such as, but not limited to:
  - ✓ State or Federal regulated wetlands or adjacent areas as locally defined
  - ✓ River, stream, lake, pond or other water resources (beds, banks or waters)
  - ✓ Designated scenic highways or vistas
  - ✓ State forestlands or wildlife management areas
  - ✓ Other designated protection areas (nature preserves, refuges, parks, etc.)
  - ✓ Contaminated sites, including hazardous, industrial or solid waste disposal sites
  - ✓ Cultural Resources and state or federal historic preservation sites
  - ✓ Endangered Species
- Any special environmental interest groups having jurisdiction over or an interest in the project.
- In all cases, the company reserves the right to require oil containment.

Where vandalism is a concern, galvanized steel grating should be used on the surface of the crushed stone. This grating shall be bonded in two places with #2 AWG solid copper wire to the transformer ground grid.

**Clear Working Area:**

A minimum of ten (10) feet clear working distance shall be maintained in front of the doors for operating and maintenance of the transformer.

Bushes, trees, walls, fences, or other obstructions shall not be planted or installed in front of the doors.

The doors of padmounted transformers shall normally face the street.

**Accessibility:**

The transformer site shall always remain accessible to Company trucks equipped for the installation, removal and continued operation and maintenance of transformers.

Access ways to transformer sites in grass areas require a solid, well-drained base under the grass. The area should be capable of supporting trucks and equipment having a maximum bearing weight of 6,500 lb. per square foot without creating a depression of more than two (2) inches. If this criteria is not met by the Customer, appropriate fill material or steel plating will be required, as determined by Company personnel, and the Customer will be responsible for the cost of any such extra measures taken by the Company.

**5.2 Padmount Transformer Foundation**

1. The designs shown in Figure 5 are adequate for transformers up to 2500 kVA without primary switching.
2. For other cases the Company shall be consulted.
3. The transformer foundation shall be installed in the following manner:
  - a. Earth beneath the foundation shall be undisturbed or well tamped.
  - b. Number 2 crushed stone shall be installed in six (6) inch well tamped layers.
  - c. Concrete reinforcement shall be installed in accordance with the attached drawings.
  - d. Concrete shall have a minimum strength of 5000 psi.
    - Poured in place concrete shall be cured for 28 days.
    - Alternatively, “High-Early” concrete shall be cured for 7 days.
  - e. Precast foundations approved by the Company are acceptable.
4. Setting of the Company’s transformer shall occur once the Customer’s concrete pad has reached full strength. If the Customer requires the transformer set earlier but not less than 7 days, the Customer takes the risk of damaging their pad and delaying service to make the necessary replacement.
5. The Customer shall provide the Company with a written report of satisfactory installation of their foundation for the Company’s transformer prior to energization. See Checklists in Figure 14.

**5.3 Vault Transformer Location, Design and Construction**

**5.3.1 General**

This information describes the minimum structural, electrical, and mechanical requirements for the installation of a transformer vault by the Customer on private property. It is not intended to be a comprehensive document, and should be used only as a guide.

The vault shall be under the sole control of the Company and accessible to authorized Company employees at reasonable hours. No other persons shall be admitted to the vault after the transformers have been energized.

### **5.3.2 Vault Design and Location**

It is the purpose of the transformer vault to isolate the transformers and other apparatus and to confine any fire that might be caused by the failure of any of the apparatus. The design, construction, and maintenance of the vault structure and its appurtenances shall reflect this concern of containment. Location of the vault access openings should be selected so as to minimize the possibility of injury in the event of a fire.

The vault shall be located above grade at an outside wall to permit good drainage, ventilation and access. It should be at a place which can be approached by a truck for delivery or replacement of transformers. A location at a parking or loading area is preferred.

### **5.3.3 Vault Construction**

It is the Customer's responsibility to determine that the fire rating of the vault will meet all applicable codes and regulations for oil-filled transformers in a building.

#### **General Notes:**

1. Figures 7 and 8 show the typical vault construction for an application with single phase and padmount transformers.
2. The vault shall have an outside door, Class A, constructed in accordance with the National Electrical Code. All doors shall be secured with a hasp for a Company padlock. A sign reading "DANGER-HIGH VOLTAGE WITHIN-KEEP OUT-ACCESS RESTRICTED TO QUALIFIED PERSONS ONLY" shall be furnished and installed by the Company on the outside of all vault doors.
3. The vault shall be drained to an 8" X 8" X 4" sump with cover located adjacent to the personnel access door. It shall not be connected to a sewer system.
4. Other than fire suppression, no pipes, conduits or other building service equipment shall be contained within the vault.
5. The Customer shall furnish and install the primary cable support in the vault where indicated by the Company.

#### **Fire Suppression:**

Where required by the local and state building code and fire protection code, the Company will permit a water fire suppression system to be installed in the vault provided the Customer is responsible for and insures the following conditions are met.

1. The system shall be designed and installed so that there is no interference in the construction, operation, or maintenance of the vault or equipment therein. Location of all pipes, detectors, sprinkler heads, and nozzles shall not interfere with any of the Company's electrical equipment or access thereof. The system shall be designed so that it can be maintained without removal, relocation, or de-energizing of any Company equipment.
2. Where possible, while still meeting code requirements, the system shall be designed so that sprinkler discharge does not reach the Company's primary or secondary connections or any other energized uninsulated parts. Location of Company equipment will be shown on drawings provided to the Customer after the vault electrical design is complete.
3. Scaled drawings, prepared and sealed by the Customer's design professional, shall be provided showing location of sprinkler heads in the vault and calculated range of water dispersion from sprinkler heads relative to the Company's primary and secondary connections. All equipment shall be accurately located on the plans.

4. All construction shall conform to the design drawings reviewed and agreed to by the Company, and shall be inspected by a representative of the Company before the system is placed in service. The Company's engineer shall review and agree to any proposed deviation from plans already reviewed and agreed to by the Company.
5. Should a Code variance be required for any reason, it is the Customer's responsibility to obtain such variances from the appropriate authority having jurisdiction and provide written notice to the Company.
6. The Customer assumes sole responsibility for proper operation of the fire suppression system.
7. The Company assumes no liability for any result or consequences of a fire suppression system that has the potential to apply water on an oil or silicone insulating fluid fire.
8. The Customer shall indemnify and hold the Company harmless for any damages resulting from operation, misoperation, or inadvertent system discharge of a fire suppression system. This indemnification shall be formalized and executed in an agreement between the Customer and the Company.
9. Should the system misoperate or discharge unnecessarily, the Customer will be responsible for vault cleanup and any costs incurred by the Company.

**Walls, Roof, and Floor:**

1. The quality of materials used in vault construction shall be of approved grade, as determined by the applicable codes and standards. Building walls, roof and floor (new or existing) meeting the requirements in this section may serve as part of the vault.
2. The vault in its entirety shall be solid masonry or concrete construction having a minimum 3-hour fire rating according to the National Electrical Code.
3. Walls shall be continuous and free of holes, deep scars, cracks, or other breaks. Seals shall be fire rated approved materials.
4. The floor shall be a level surface, adequately reinforced to support loads specified by the Company for its equipment.
5. Should the Customer be concerned about any possible undesirable sound or vibration transmission to other portions of the building, any soundproofing is their responsibility. Should the Customer desire to support the transformers on soundproofing devices, any device should be fabricated so as not to exceed 2" thickness and so that it will hold its dimensions over time given the weights involved and variation in vault temperature.

**Ventilation:**

1. Vaults shall be ventilated to the outside through openings that are located, arranged, sized, covered, and constructed in accordance with the National Electrical Code and specific requirements noted below. The exhaust area shall not be less than the inlet area. A roof type exhaust ventilator is preferred for one-story structures.
2. Ventilation capacity shall be furnished for the maximum transformer capacity of the vault, even though the initial transformer installation may be less than maximum capacity. The ventilation design shall be submitted to the Company for review.
3. Extreme caution shall be exercised in the design, routing, and installation of ventilating systems. Exhaust openings to outside walls should not be located adjacent to other openings that serve or could serve as air intakes. Exhaust openings should be located as far as possible from doors, windows, fire escapes, and combustible material, and at an adequate elevation above grade. Duct facilities should not be routed through areas where system leaks (possibly initiated by explosion) could result in the escape of potentially toxic gases or residue to occupied areas.
4. Intake and exhaust openings shall be equipped with rustproof metal louvers and 1/2" mesh rustproof screens where they meet the outside air. The exhaust ducts shall be located high in the vault and the intake ducts low a minimum of 4 inches above final grade or floor, both suitably spaced to provide air circulation around transformers. Fire

dampers, when required by the local and state building code and fire protection code, shall be #10 gauge galvanized steel minimum constructed in accordance with ANSI/UL 555 "Standard for Fire Dampers". Links shall allow dampers to fall or rotate closed in the event of fire, but not as a result of excessive transformer temperature. In addition, the dampers shall be arranged so that operation of a forced air blower does not hold them open.

5. If a forced air ventilation system is required, the Customer will, at their expense, install, maintain, and provide energy for a thermostatically-controlled ventilation system designed to move outside air through the vault.
6. Power supply to the blower shall be connected from the load side of the Customer's meter. An adjustable thermostatic control shall be provided for automatic operation, with a manual on/off switch. Controls and a safety switch shall be located inside the vault near the door. All other ventilation equipment should be externally located.

#### **5.3.4 Vault Maintenance**

Should the vault require maintenance, it will be brought to the attention of the Customer and shall be promptly repaired with a Company representative in attendance.

1. Customer access to Company controlled electrical spaces within Customer-owned electric facilities:

The Company's control of electric spaces in Customer-owned electric facilities is for the sole purpose of protecting the integrity of the Company's energy supply and security of the utility metering equipment. Any costs shall be determined by the Company's filed tariff. In these requirements, "Customer" refers to the Customer or their agent. Under this and all other policies, it is expected and it is the Customer's responsibility to provide a qualified person as defined in the National Electrical Code and any other applicable codes.

- a. The Company can provide isolation and tagging (and grounding upon customer request), if requested, at the Company's primary isolation point on the supply line ahead of the Customer's service equipment. However, the Customer is solely responsible for the protection of personnel who work on their de-energized equipment.
  - b. When the Customer does not require isolation and tagging on the supply line and needs access to Company-controlled electrical spaces for their maintenance purposes, the Company in its sole judgment may determine the ability to grant access to the Customer for the duration established by the Company. When granted, the Company will witness the Customer's placement of their lock immediately after the removal of the Company's lock. Upon notification by the Customer that their work is complete, the Customer shall relinquish access back to the Company and the Company's lock shall be placed immediately upon the removal of the Customer's lock. In each case the transfer shall occur in the presence of both parties. The Company will check its electrical equipment for any signs of tampering.
2. In the event that the required access is of short duration and the Company's representative remains on site to avoid a second trip, it is understood they are doing so without any supervisory or oversight capacity relative to the Customer.

#### **5.4 Service Operating Procedures**

The Customer is responsible for having qualified personnel available at all times to perform the operating functions for their service equipment.

## 6.0 GROUNDING

The following grounding criteria are for the sole purpose of grounding the Company-owned transformer and based on a moist, sand-clay soil type. The Customer is responsible for installing their own service entrance ground in accordance with Section 6 of ESB 750 and the NEC. The Customer may install the ground grid with approved materials exceeding the minimum criteria below for situations such as varying soil conditions and special requirements specified by an authority having jurisdiction.

### 6.1 Padmounted Ground Grid Installation

- A ground grid shall be installed by the Customer, consisting of bare copper conductor soft drawn 19 strand, minimum size #2/0 AWG, buried in the pattern of an outer loop around the transformer pad. Refer to Figure 3.
- The loop shall be connected to at least 2 driven ground rods (one at each opposite corner) at not less than eight (8) feet from each other. If ground rods cannot be driven, consult the Company for an alternate design that allows the installation of a counterpoise system.
- Two grounding connections shall be provided by the Customer from the ground grid to the transformer.
- A length of conductor, at least 3 feet above the top of the pad, shall be provided for each connection.
- The ground connections to the transformer tank will be made by the Company.
- Metallic primary and secondary conduits shall be bonded by the Customer to the ground grid with #4 AWG Cu (solid).
- Where practicable, the ground grid shall be bonded to a continuous metallic water system.
- Ground connections shall be exothermic or pressed type.

### 6.2 Vault Ground Grid Installation

Ground rods and a continuous #4/0 AWG bare copper or equivalent ground bus shall be furnished and installed in the vault by the Customer as shown in Figure 3. Non-current carrying metallic parts of equipment in the vault will be connected to the vault ground. Where practicable, the vault ground shall be bonded to a continuous metallic water system or building ground by the Customer.

### 6.3 Ground Grid Resistance for Installations Supplied from delta 2.4kV, 4.8kV, 12kV and all 23kV and 34.5kV systems

For delta systems less than 15kV, the ground grid installed by the Customer shall have a ground grid resistance of 25 ohms or less. For all systems greater than 15kV, the ground grid resistance shall be determined by the Company.

The ground resistance of the ground grid shall be verified by the Customer in accordance with IEEE Standard 81 before connection to the water pipe or other grounding systems. The test shall be performed using a Biddle ground tester, or by other suitable means, to be assured that the ground resistance is no greater than the value specified by the Company. A copy of the test results shall be provided to the Company.

Ground grids not achieving the values prescribed by the Company shall be augmented with additional ground rods installed a minimum of 8 feet from the existing ground rods and connected to the transformer ground grid with a minimum #2/0 AWG copper soft drawn 19 strand.

#### **6.4 Ground Grid Resistance for Installations Supplied from wye 5kV Class and 15kV Class Systems**

Due to the nature of these continuously grounded distribution systems, the grounding method described in section 6.1 is sufficient protection and does not need to be measured or augmented.

#### **6.5 Ground Grid Integrity**

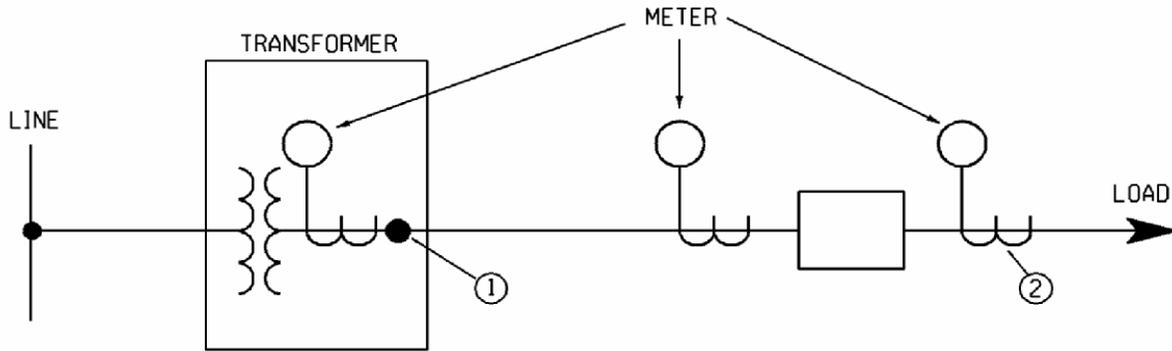
It is the Customer's responsibility to ensure the integrity of their ground grid to meet ground grid resistance requirements and longevity of the installation.

### **7.0 CUSTOMER'S SERVICE EQUIPMENT and COMPANY METERING**

- Service equipment and metering transformers shall not be installed in the transformer vault.
- Refer to ESB 750 Sections 5 and 9 for the Customer's service equipment installation requirements.
- Refer to ESB 750 Section 7 for the Customer's provisions to be made for the Company's metering.

### **8.0 PRE-ENERGIZATION REQUIREMENTS**

The Customer shall provide the Company with a written report of satisfactory installation including the checklists completed in Figure 14 as a minimum. This shall be submitted upon the issuance of the third party electrical inspection approval certificate for the service connection.

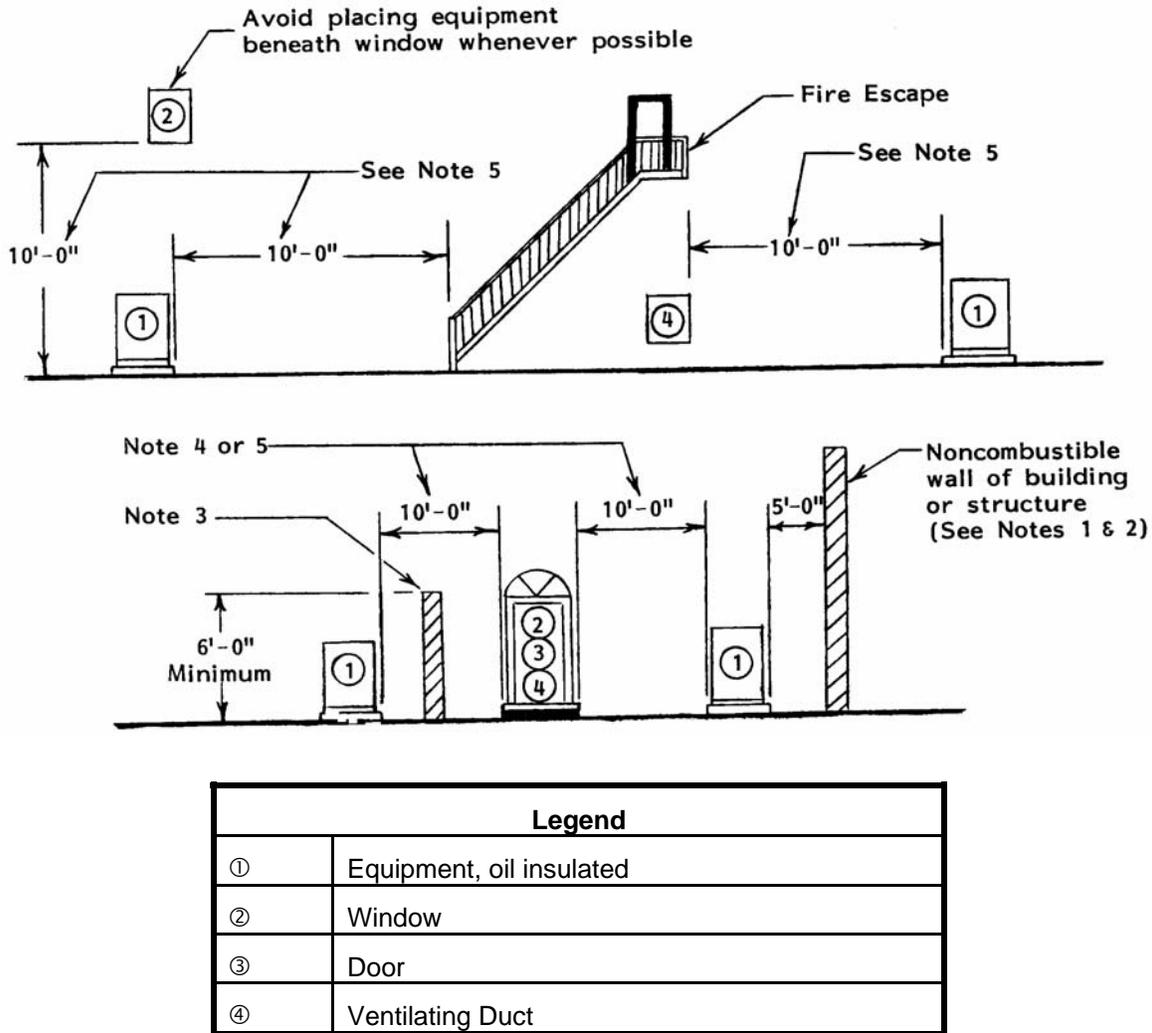


PRIMARY SUPPLY	PADMOUNT LOCATION & FOUNDATION	SECONDARY CABLE & CONDUIT	MAIN SERVICE EQUIPMENT	METERING
BULLETIN REFERENCE:	BULLETIN REFERENCE:	BULLETIN REFERENCE:	BULLETIN REFERENCE:	BULLETIN REFERENCE:
SECTION 4.0	SECTION 4.0 SECTION 5.0 SECTION 6.0	SECTION 4.0	SECTION 7.0	SECTION 7.0

NOTES

1. Secondary terminal connection point inside padmount transformer
2. Cold sequence connection required for metering CT's and self contained meter sockets when more than one tenant customer is served from the premise owner's service connection

**FIGURE 1 SERVICE INSTALLATION DIAGRAM – THREE PHASE PADMOUNTED TRANSFORMER**



**Notes:**

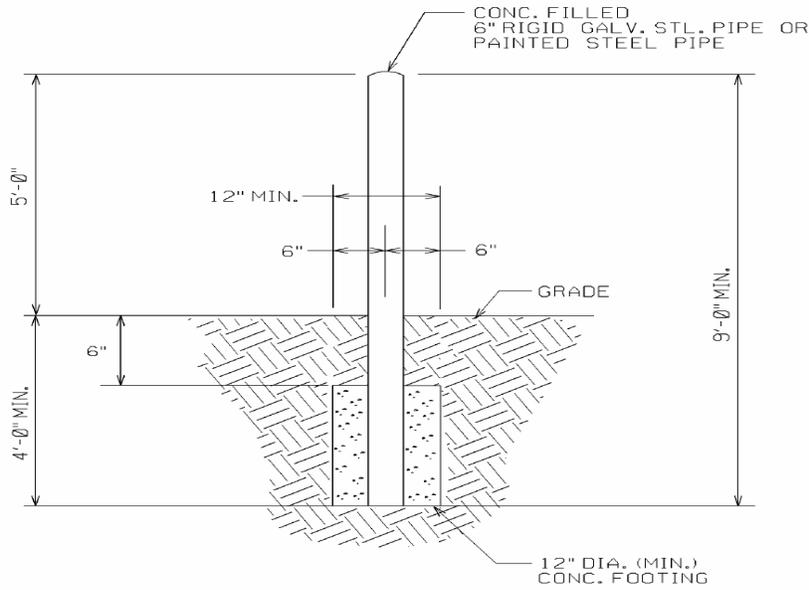
1. Noncombustible material is defined as a material that will not ignite, burn, support combustion or release flammable vapors, when subjected to fire or heat, or as described by the latest edition of the NFPA-220.
2. No portion of a building or building structure shall overhang any part of the pad-mounted equipment.
3. In cases where required distances cannot be met, a noncombustible barrier, 6 foot minimum height, shall be constructed. This barrier shall be designed to provide adequate fire protection to the existing structure. A design for this structure shall be prepared and sealed by the customer's Professional Engineer or Registered Architect and shall further be approved by the local authority having jurisdiction of building code enforcement.
4. For exits from a public assembly room, such as an auditorium, a 10 foot minimum clearance should be increased to 25 feet, unless there is a barrier.
5. This requirement may vary between individual states. Refer to the building code regulations for the state involved.

**FIGURE 2                      THREE-PHASE PADMOUNTED TRANSFORMER  
REQUIRED CLEARANCES**

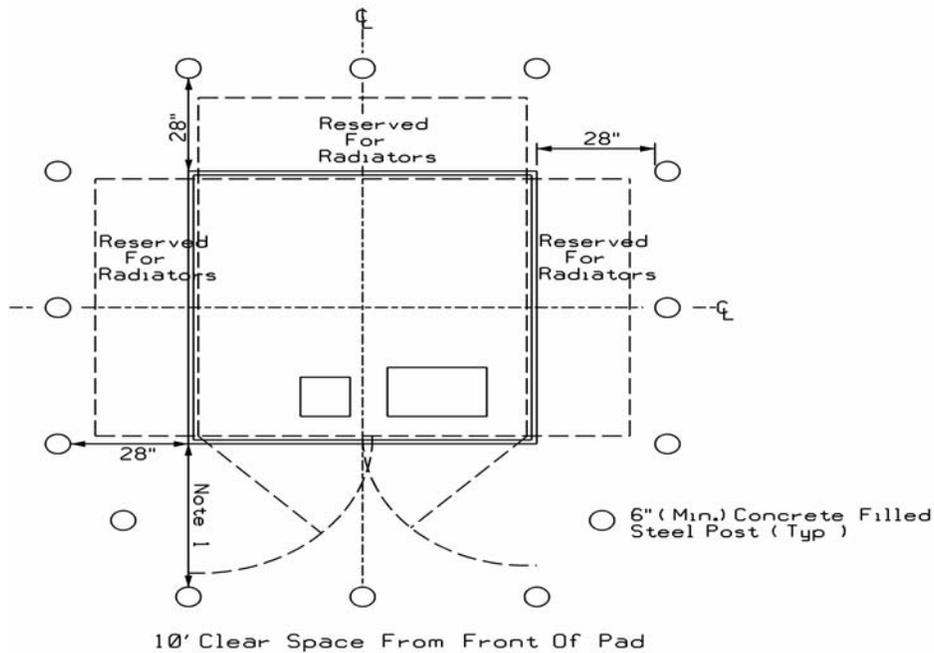
6. . Clearances from objects:
- A. An area measuring 10 feet from any point of the transformer pad shall be kept free of all:
- buried water lines, storm drainage lines, gas lines, other electric lines;
  - underground fuel storage tanks; and
  - above grade fire hydrants, cell towers, self contained diesel or diesel byproduct fueled generators, and outdoor enclosed generators.
- B. An area measuring 25 feet from any point of the transformer pad shall be kept free of all:
- exposed water lines, gas piping, sewer lines;
  - open conductor electric lines; and
  - above grade gas meters or regulator vents, fuel storage tanks or dispensing units, and non-enclosed gasoline fueled generators.

**NOTE:** The 25 ft. clearance may be reduced to 10 ft. with a noncombustible barrier (see Note 3) and shall not be less than five (5) feet from the edge of the transformer pad. The Customer or their authorized representative shall obtain this clearance reduction approval from the Company and the local AHJ, as necessary, prior to the noncombustible barrier installation.”

**Figure 2** (cont'd)



TYPICAL  
BOLLARD DETAIL



**Notes:**

1. 6 foot minimum clearance.
2. If bollards are required for transformer with oil containment, locate bollards 6 feet from edge of pad, where applicable.
3. The Company shall designate the number and location of Bollards to the Customer's installer by marking the Bollards of this figure as follows:

<b>Bollards Required</b>	●
<b>Bollards Not Required</b>	⊗

**Figure 2** (cont'd)

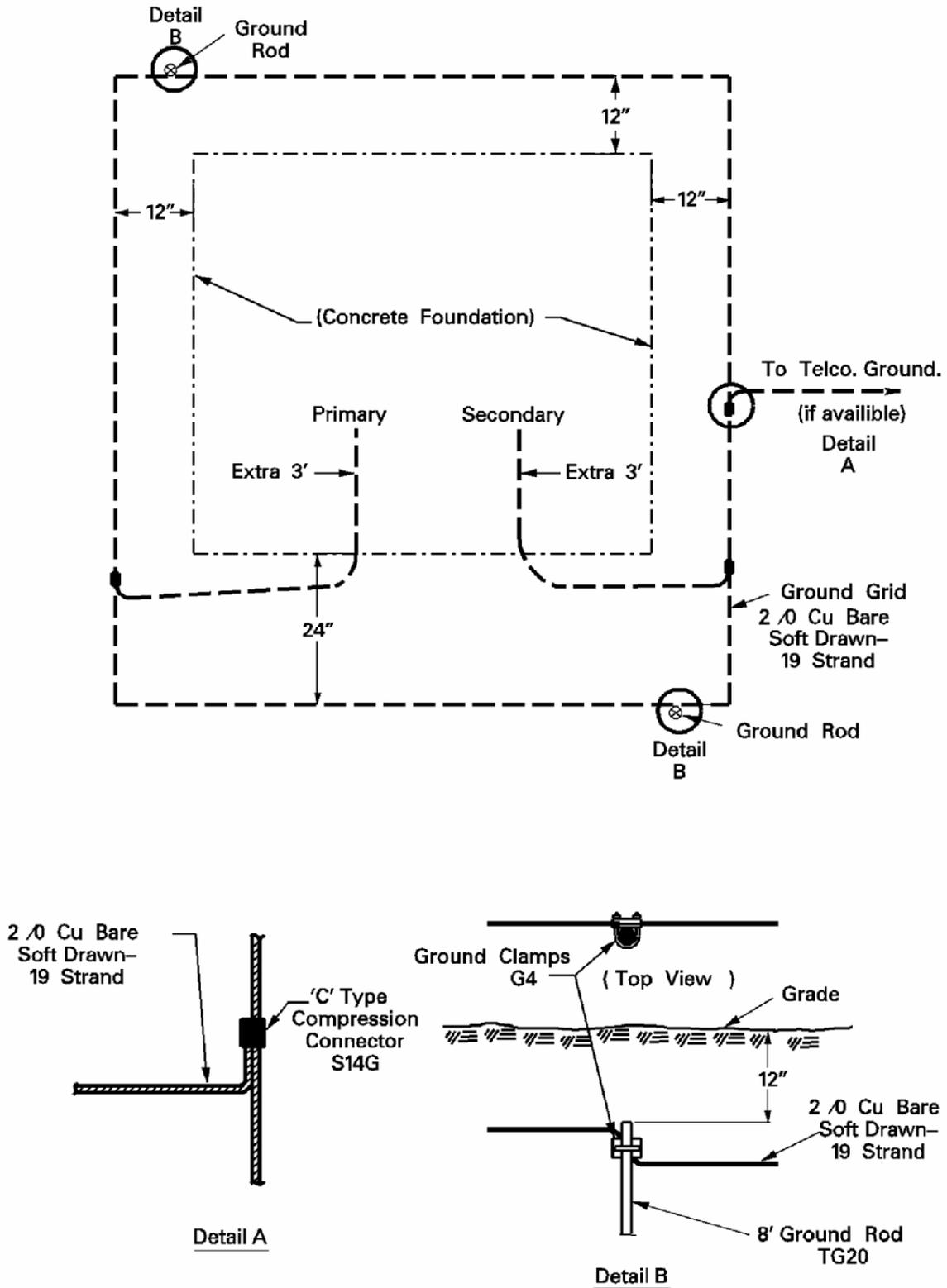
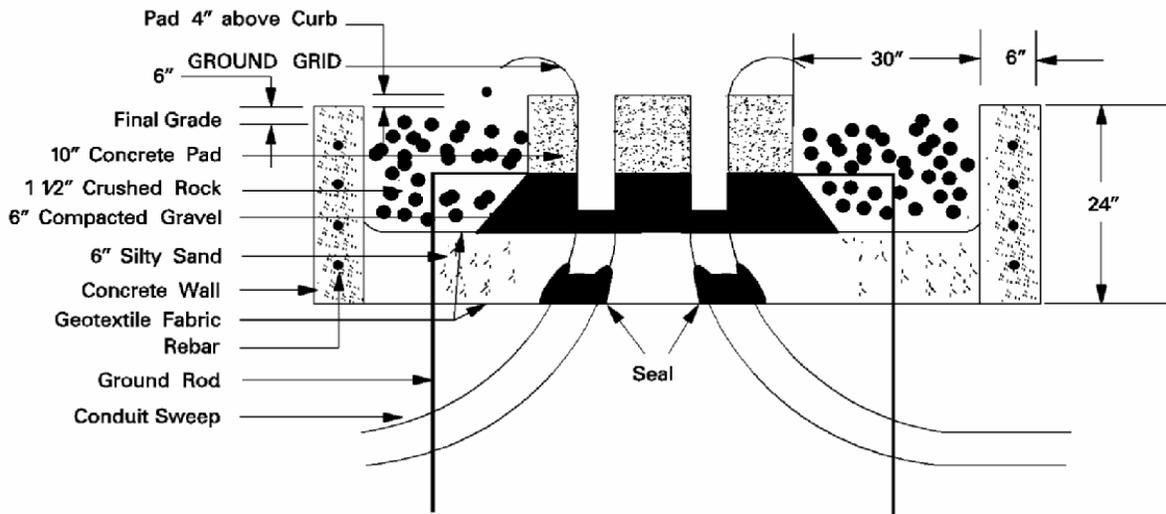
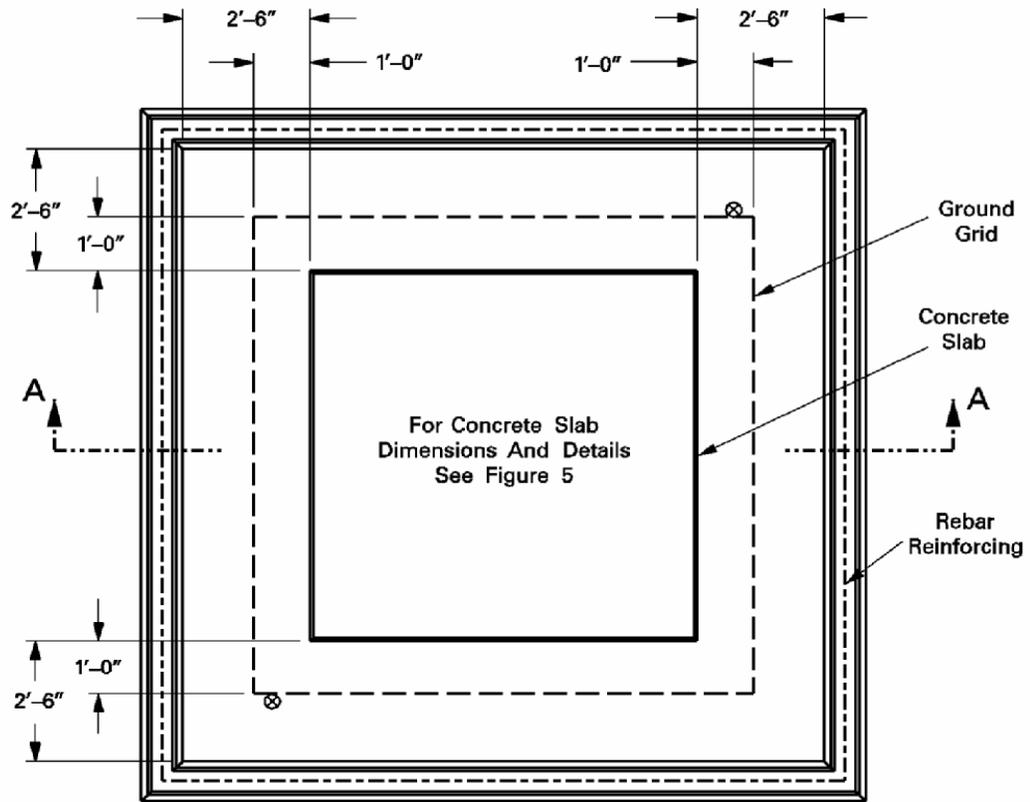


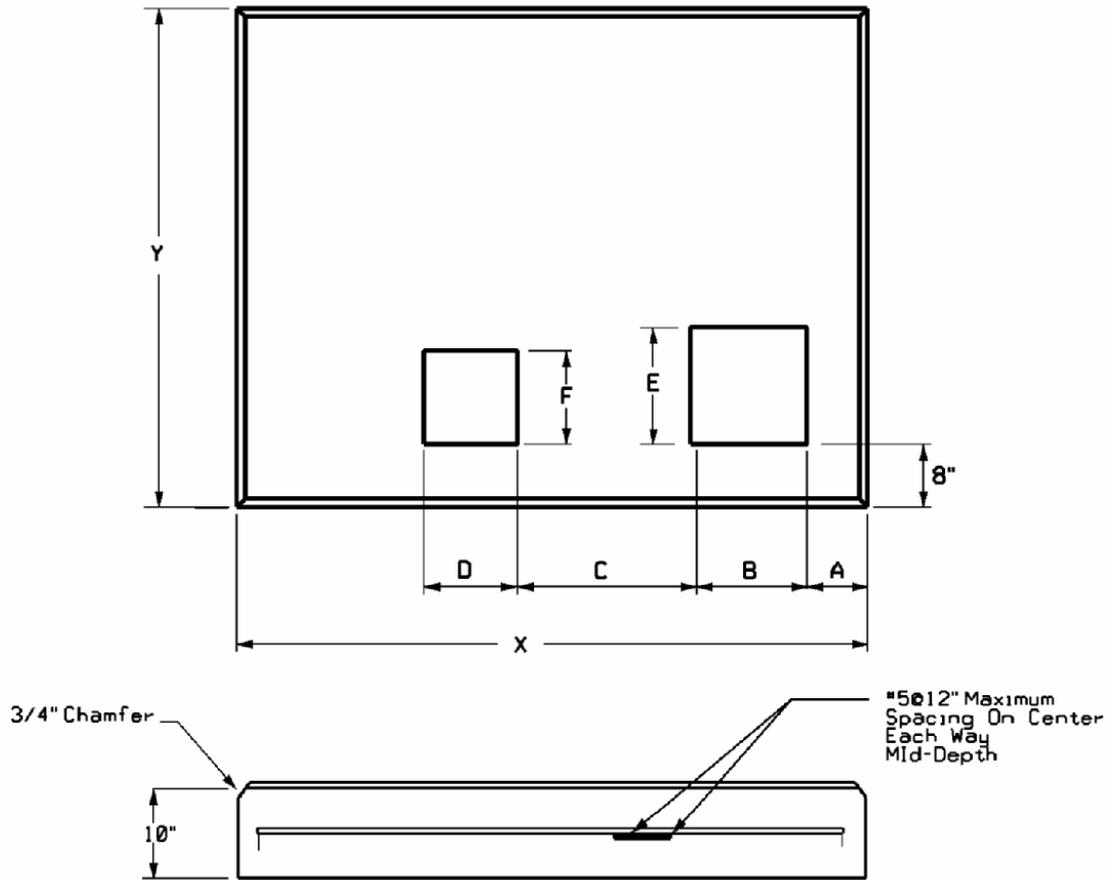
FIGURE 3

GROUNDING PLAN  
THREE-PHASE PADMOUNTED TRANSFORMER



Typical Detail

FIGURE 4 OIL CONTAINMENT CURB (IF REQUIRED)



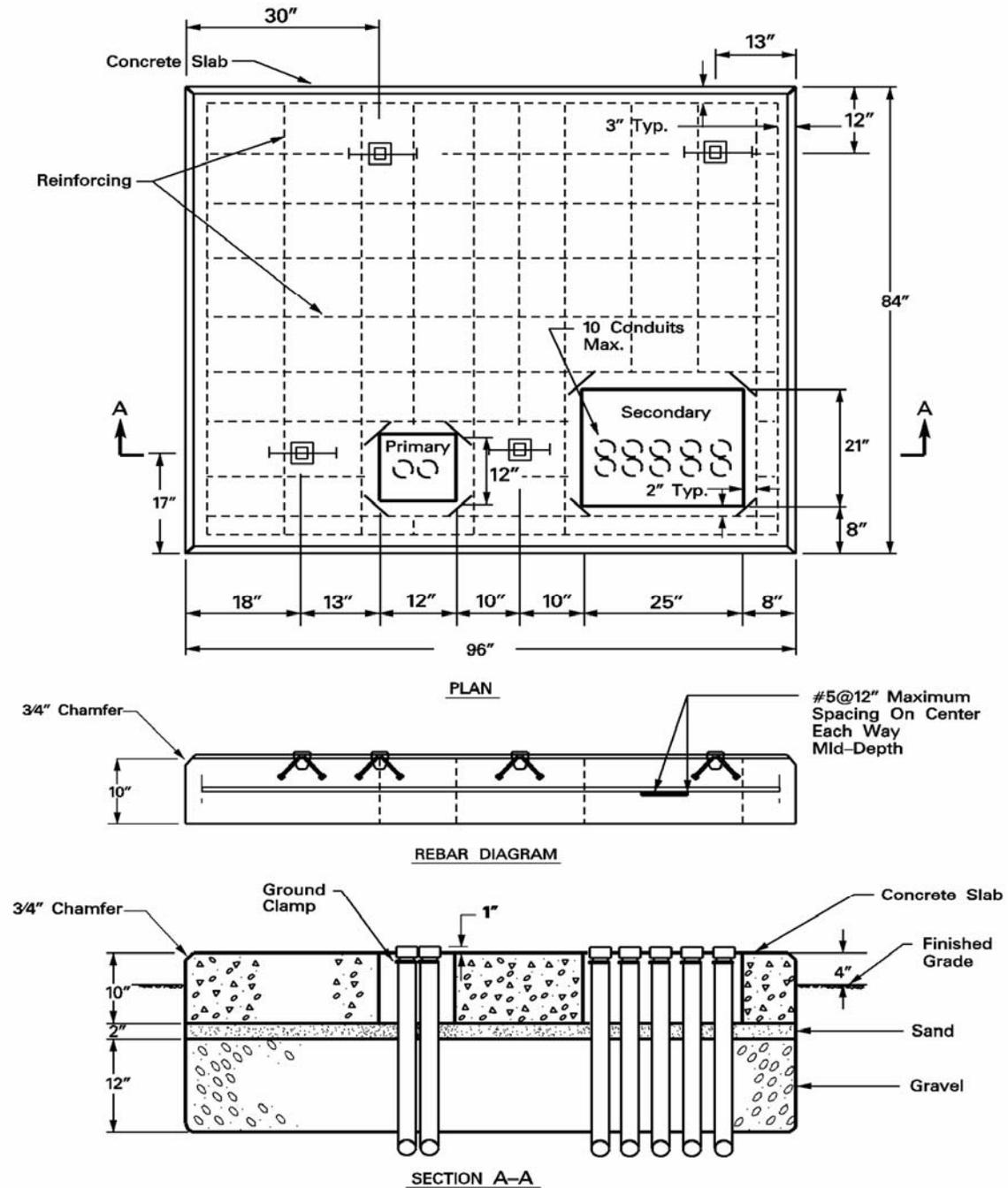
REBAR DIAGRAM

3 PHASE PADMOUNTS		15 kV		25 and 35kV	
Dimensions		75-500kVA	750-2500kVA	75-300kVA	500-2500kVA
X		81"	83"	85"	96"
Y		64"	82"	62"	84"
A		22"	12"	8"	8"
B		15"	25"	15"	25"
C		8"	8"	20"	20"
D		12"	12"	12"	12"
E		15"	15"	18"	21"
F		12"	12"	12"	12"

Notes:

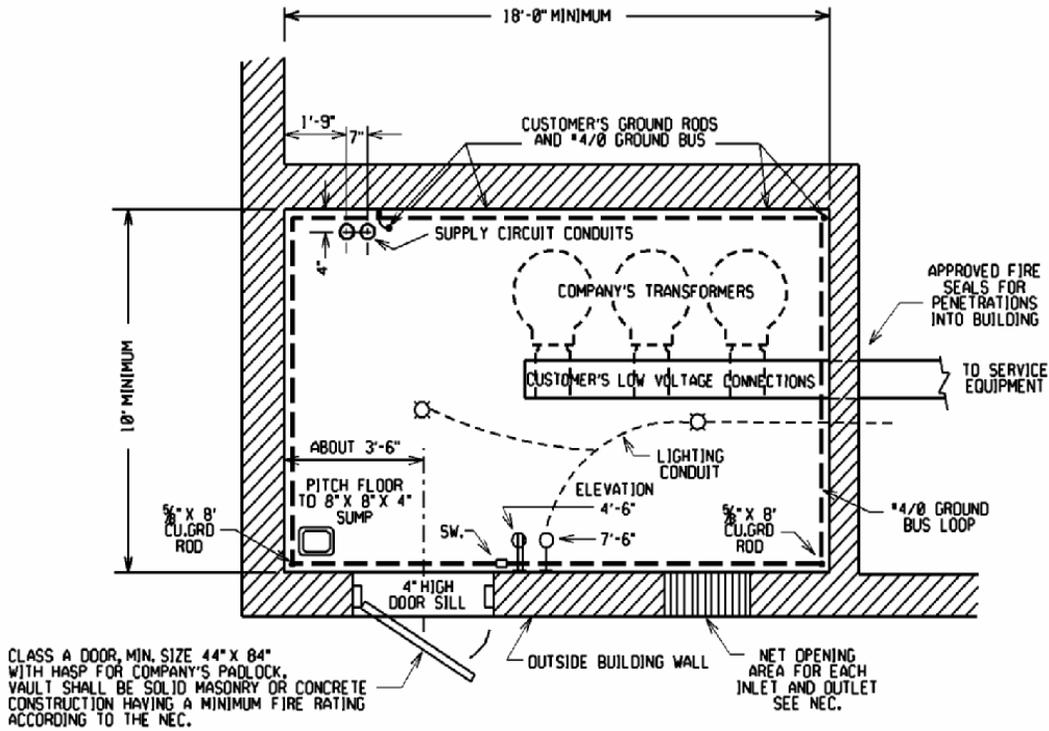
1. All materials and workmanship shall conform to ACI-318.
2. Concrete to have a minimum strength of 5000 p.s.i. after 28 days.  
Air entrainment to be 6% ± 1%. All exposed edges to have a 3/4" chamfer.
3. Reinforcing to be #5 - Grade 60 bars and shall conform to ASTM A-615 of latest date.  
Reinforcing to be placed a minimum of 2" clear from face of concrete.
4. All openings shall have additional rebar reinforcement of 1 - #5 each corner, mid-depth.
5. Lifting anchors shall be installed with appropriate Dayton lifting anchors or equivalent.

FIGURE 5 TYPICAL TRANSFORMER CONCRETE PAD DIMENSIONS

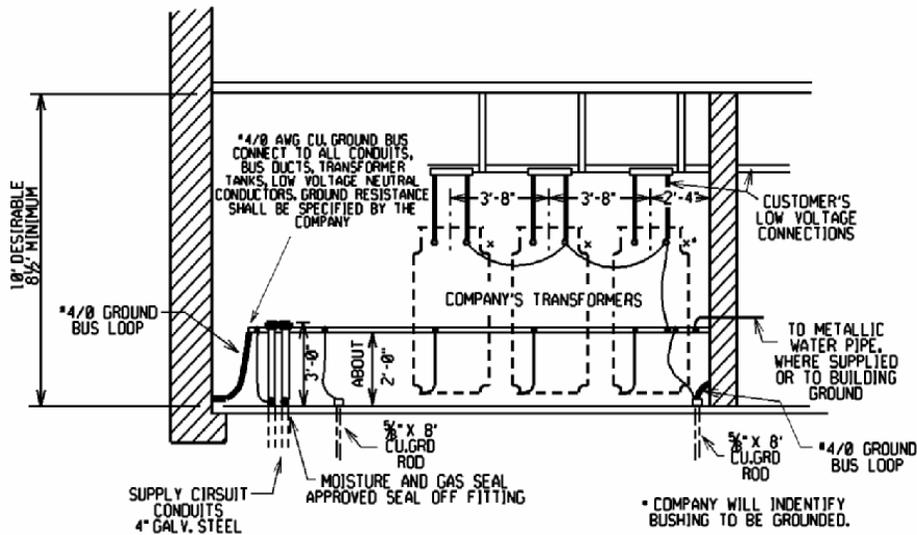


NOTE: Customer shall seal secondary conduits with expanding foam and shall also grout primary and secondary conduit openings on pad. Company shall seal primary conduits as deemed necessary.

**FIGURE 6** Reinforced Concrete Flat Pad Three-Phase, Padmounted Transformers (Typical Conduit and Foundation Reinforcing Schedule)



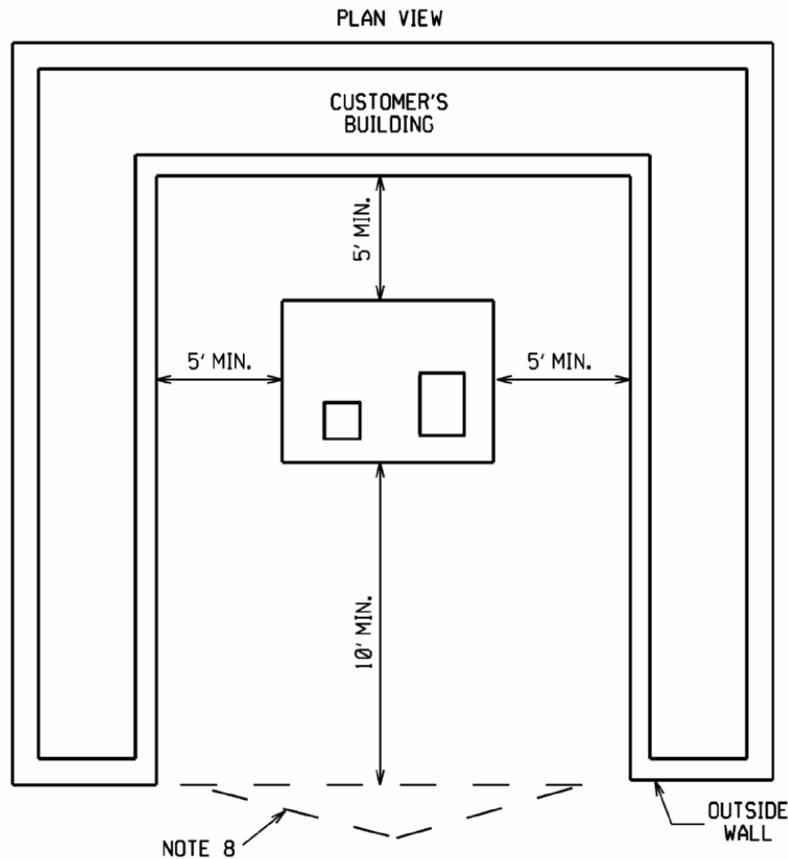
PLAN



ELEVATION

Typical Above Grade Transformer Vault  
Customer's Three Phase Service Less Than 600V

FIGURE 7



**NOTES:**

1. Raised concrete pad reinforced with welded wire fabric with dimensions as shown in figure 8, except pad shall be 4 inches above the floor.
2. Conduits to be arranged as shown in Figure 6 and installed to 1" above top of the pad. Conduit entry shall be designed to prevent oil from spilling into other parts of the building.
3. Vaults with padmount transformers do not have to be secured.
4. For vaults with no outside wall, a 4 inch curb shall be installed. If the top of the curb is 4 feet or more above the adjoining outside area a removable handrail shall be provided along with a 36" wide stairway for access to the vault. The top step of the stairway or landing shall be at the same elevation as the curb.
5. For vaults with an outside wall, the opening for the padmount transformer installation shall be the same height as the vault ceiling and six feet wider than the transformer pad. The opening shall be centered on the transformer pad.
6. Vault height shall be determined by the Company based on the transformer size and access to the area in front of the vault by Company vehicles.
7. Dotted line in drawing shows required fence, for installations that are not enclosed by the building for transformer and equipment that is not padmounted.
8. Fence installations shall have a 10' wide X 12' high door located in front of transformer for maintenance of equipment.

**FIGURE 8** Typical Above Grade Transformer Vault with Padmounted Transformer – Customer's Three Phase Service Less Than 600V

SIDE VIEW FIG #8

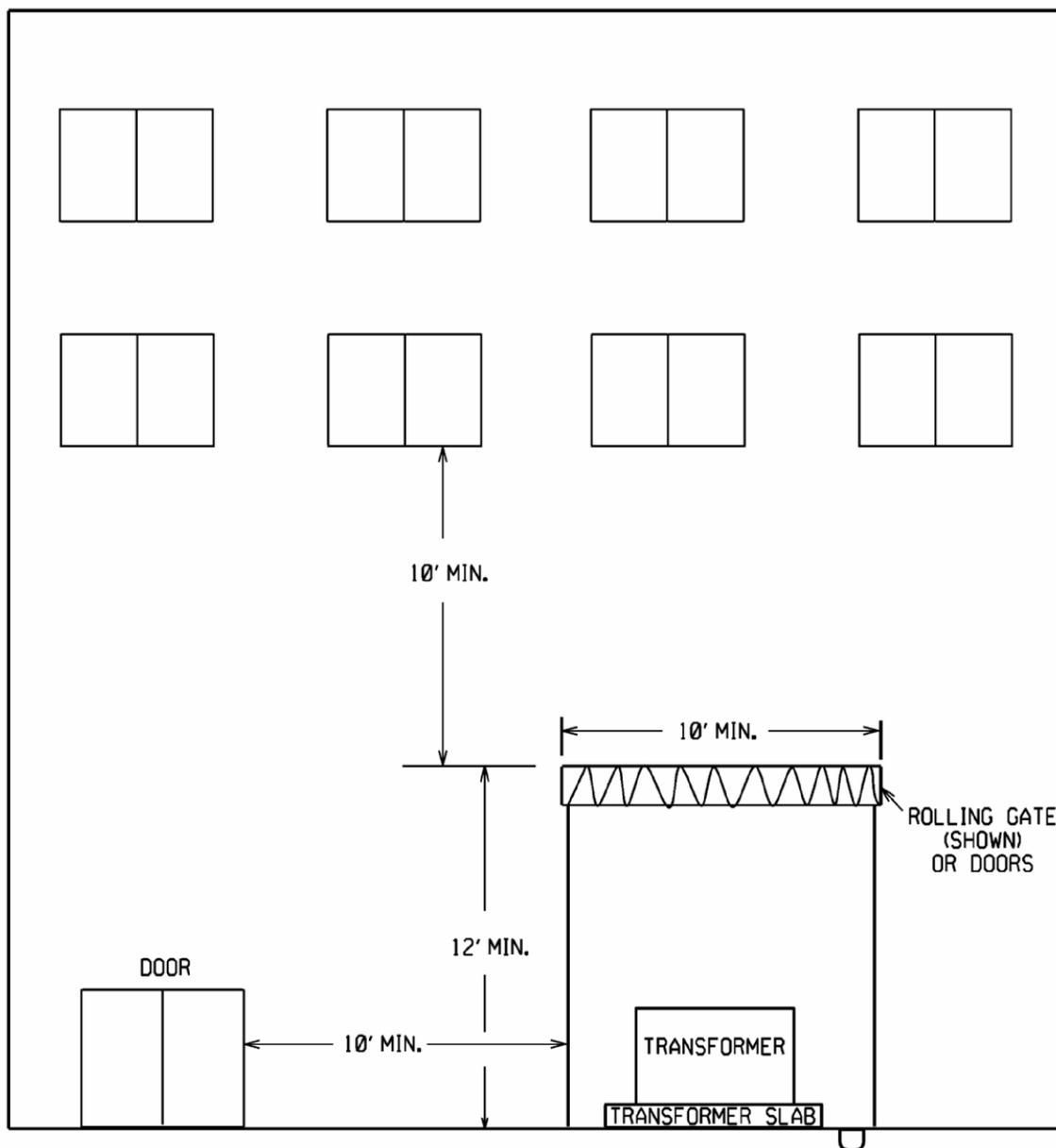
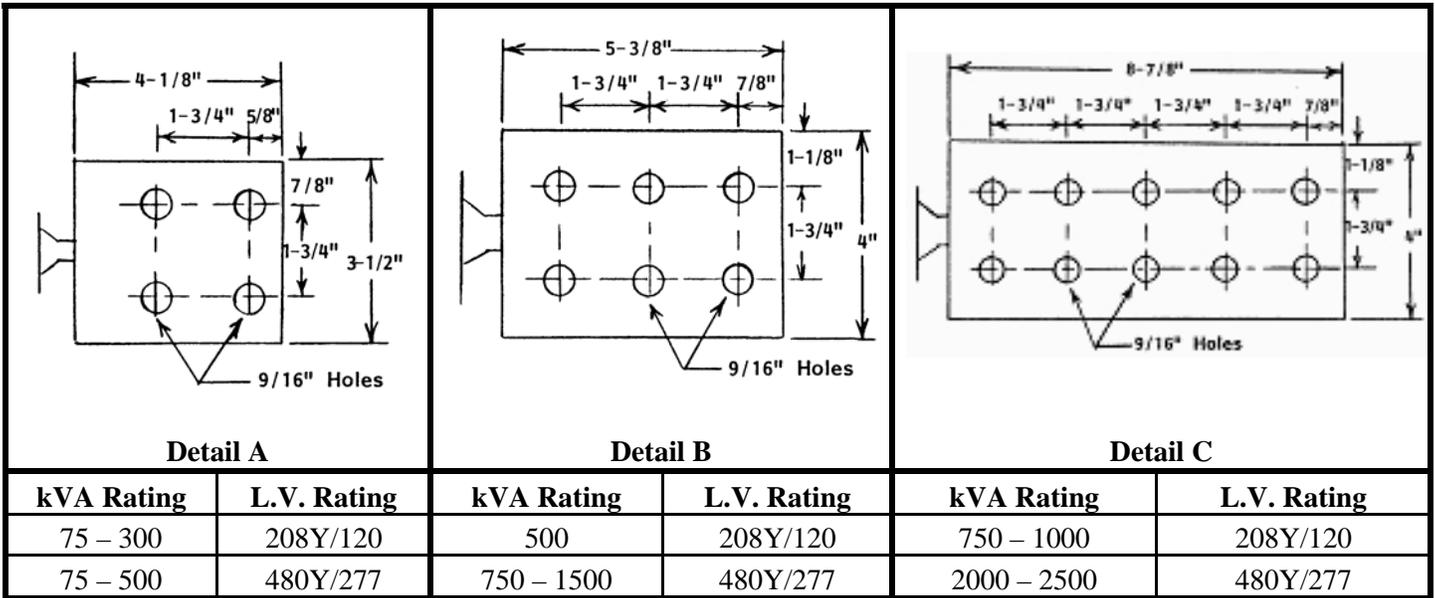


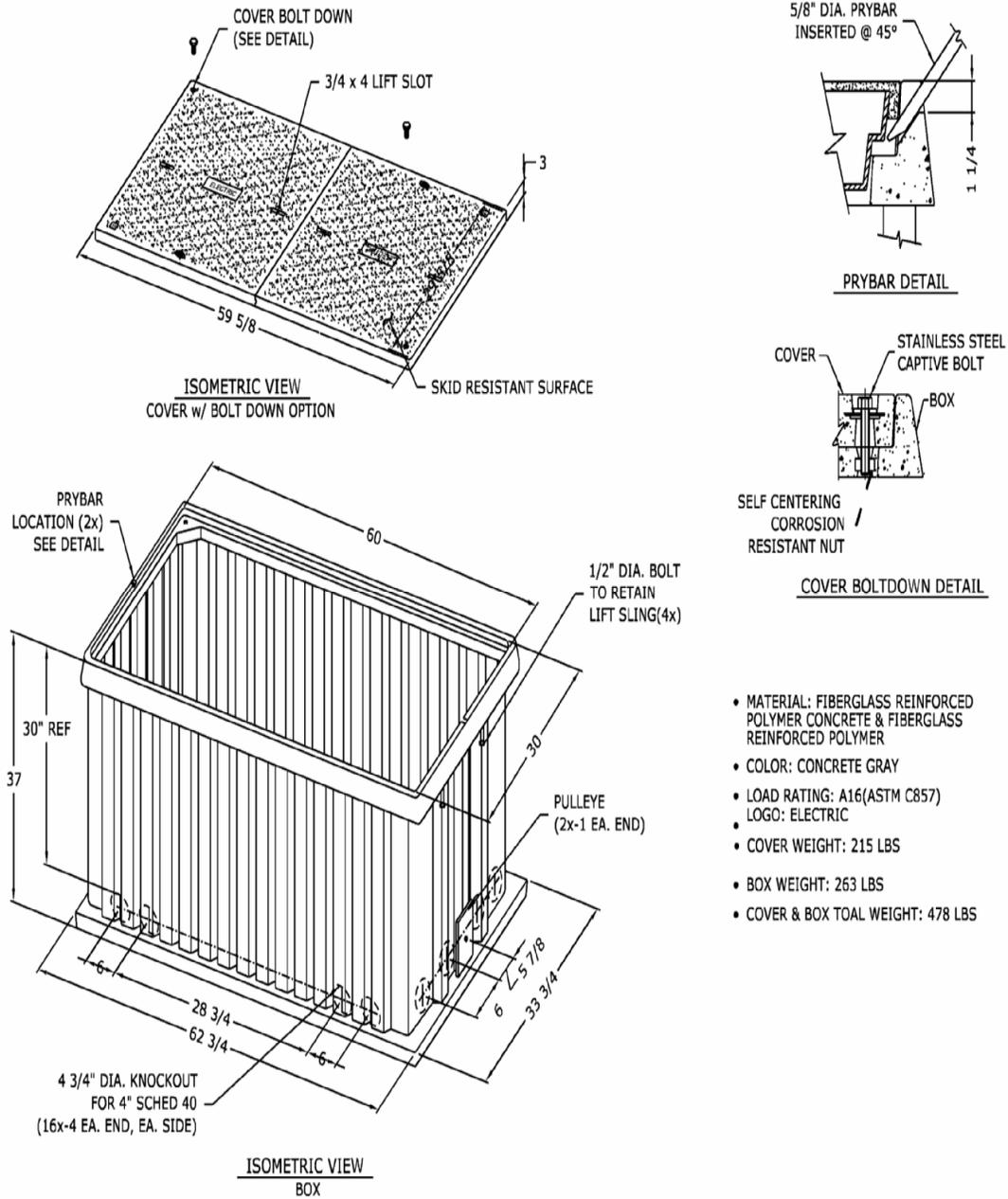
FIGURE 8  
(Cont'd)

Typical Above Grade Transformer Vault with Padmounted  
Transformer – Customer's Three Phase Service Less Than 600V  
VERTICAL PROFILE



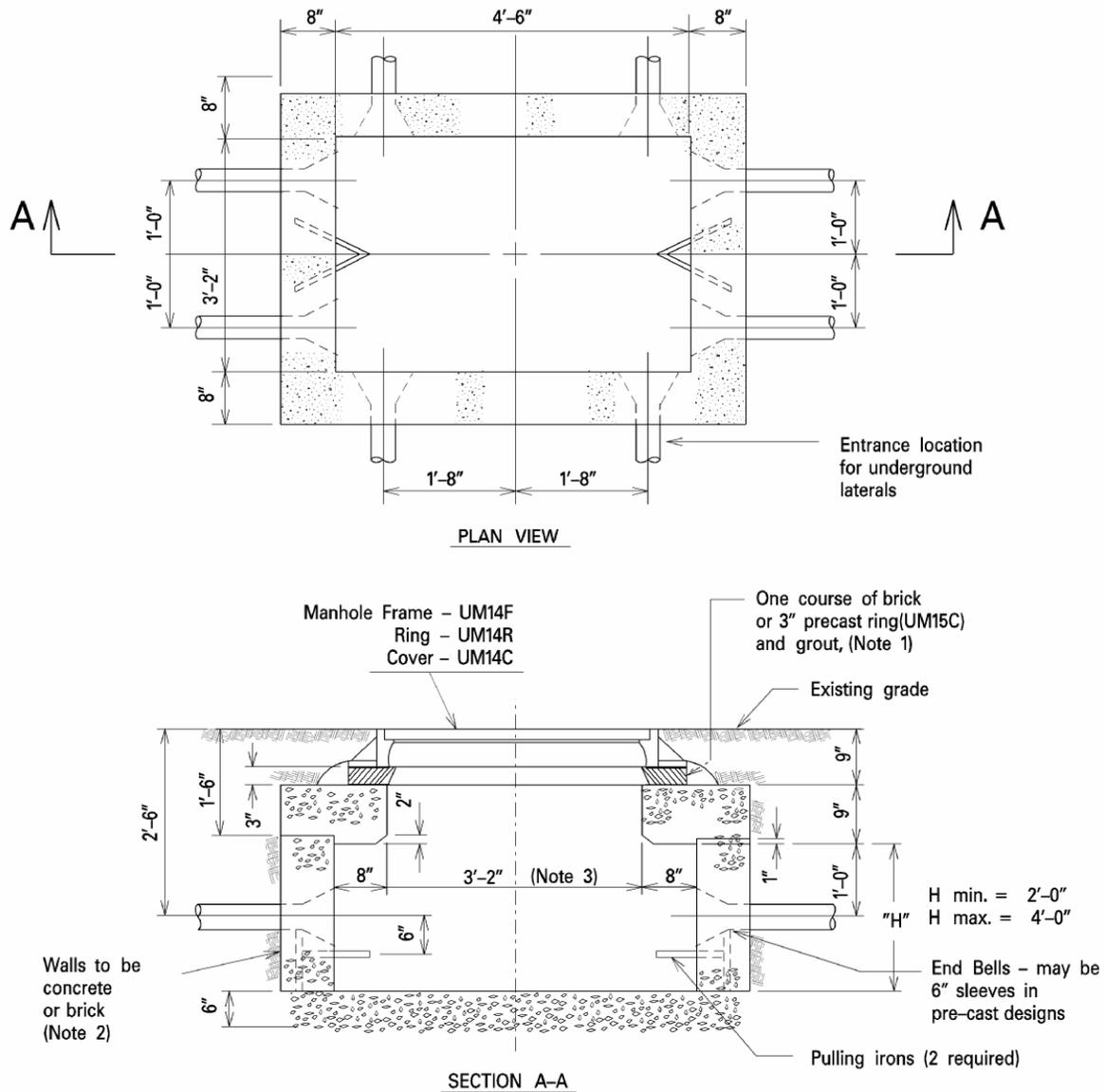
All Company padmounted transformer spade terminals are shown in Details A, B, and C. Minimum secondary conductor connector thickness shall be 1/4 inch, with 9/16 inch diameter holes.

**FIGURE 9** Secondary Connections to Padmounted Transformers



**FIGURE 10**

**Typical Primary Cable Handhole Construction**



NOTE: Where splicing is necessary for one set of #4/0AWG cables, a heavy duty handhole may be used as shown. For multiple sets of #4/0AWG cables, or cables larger than #4/0AWG a manhole, per Figure 11, shall be used.

**FIGURE 10** Typical "Heavy Duty" Primary Cable Handhole Construction (cont'd)

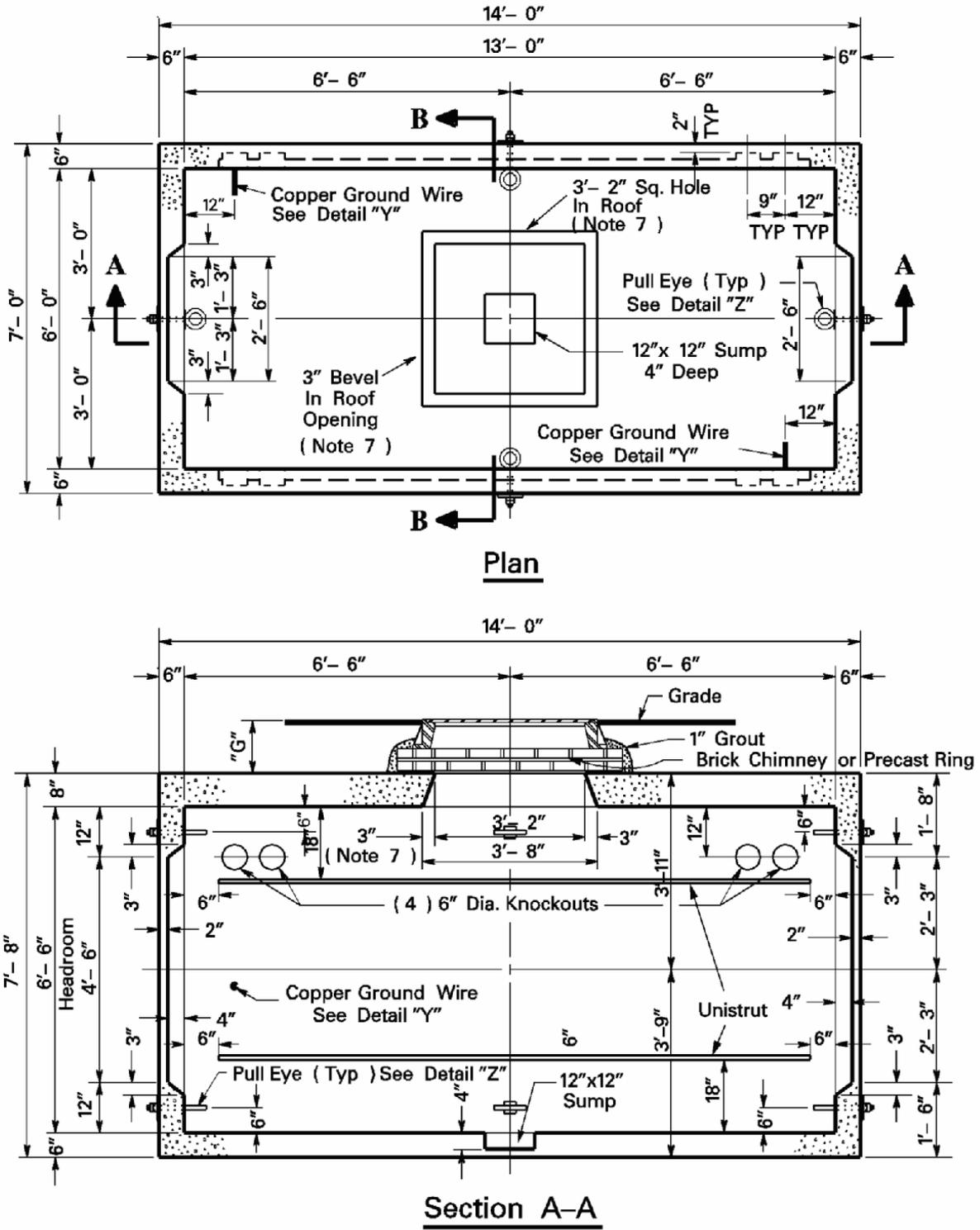
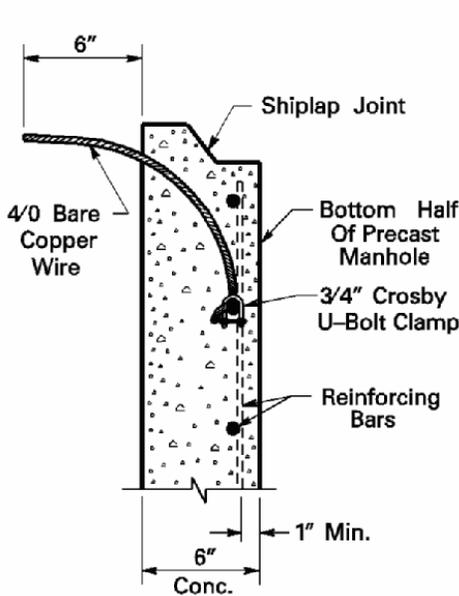
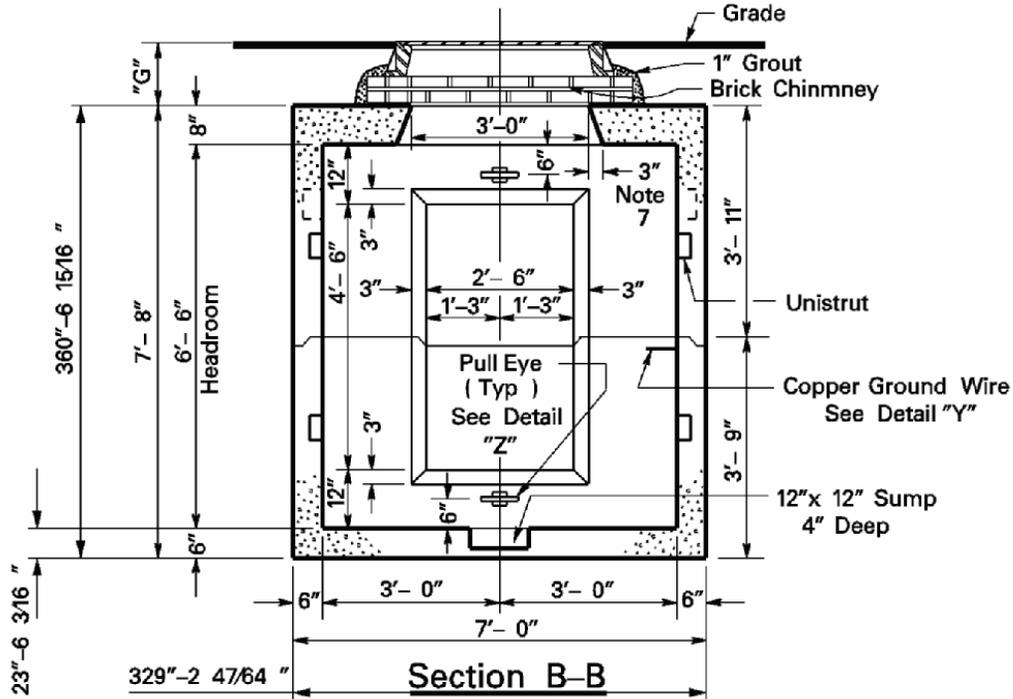
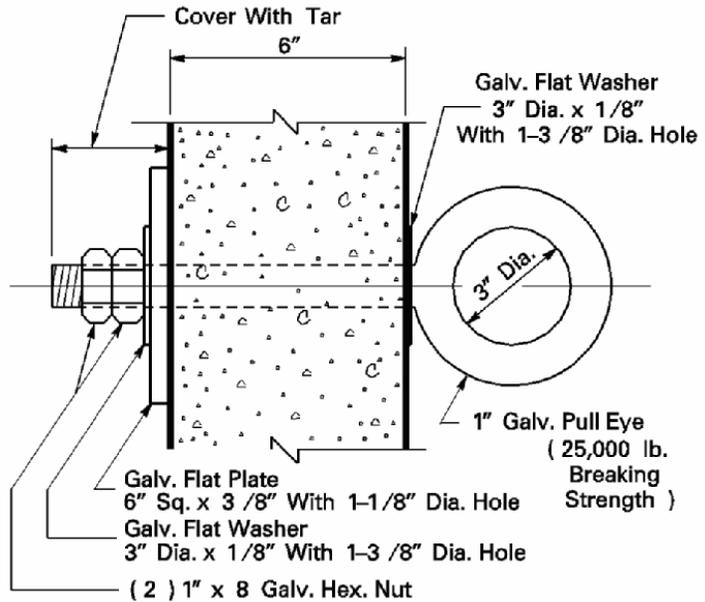


FIGURE 11

Typical Manhole Requirements



**Detail "Y"**  
 2 Required



**Detail "Z"**  
 4 Required

Note: Construction joint to be sealed with asphalt or equivalent.

**Figure 11 (cont'd)**



## NOTES

1. Concrete minimum strength - 5000 P.S.I., 28 days
2. Steel reinforcing bars shall conform to ASTM-A-615 (latest revision). Grade 60 min. Cover - 1".
3. Design loading - the roof shall be designed for AASHO-HS20-44 direct wheel loading.
4. Do not extend horizontal rods into duct openings. Vertical reinforcing rods in top and bottom sections of the duct openings will be bent out in the field for support of incoming duct bank.
5. Pull eyes, furnished by manufacturer, to be 1" round galvanized eye bolt. Pull test 25,000 lbs. As per detail "Z".
6. Bare 4/0 copper ground stub conductor and U-bolt clamps as shown in detail "Y" to be furnished by manufacturer.
7. Manholes to be supplied with a 3'-2" square hole in roof with a bevel between 1 ½" and 3" as standard.
8. Construction joint shall be sealed with asphalt or equivalent.
9. Customer will provide manhole frame, cover, end bells and brick.
10. Manholes to be in accordance with ASTM publication C-857 and C-858.
11. Manhole to be delivered to the job site by the manufacturer. Delivery to be coordinated by the Customer.
12. Unistrut to be 1-5/8" x 1-5/8" galvanized steel.

**Figure 11** (cont'd)

- NOTE #1 Insulating bushing.
- NOTE #2 Galvanized steel conduit and bend are to be used, they shall be grounded by bonding to an approved U-bolt type ground clamp 6" (150 mm) from top of the conduit. A 24" (600 mm) conductor shall be provided to extend to the Company's grounding conductor. The conductor shall be sized as required by the National Electrical Code, Article 250, but in no case shall it be smaller than #4 AWG copper. Recommend use of corrosion resistant bend in locations subject to highway salting. See Section 4.1.9 in EB 750.
- NOTE #3 Galvanized steel conduit, galvanized steel sweep, attachment clamps, grounding clamp and 24" grounding conductor shall be furnished and installed by Customer. Normally, the conduit shall rise on the side of the pole away from traffic up to 8 ft. (2.5 m) to 11 ft. (3.4 m). Consult company for proper location on pole.
- NOTE #4 Pipe straps, install at not more than 30" (750 mm) intervals.
- NOTE #5 The conduit burial depth shall be 30" (750 mm) minimum.
- NOTE #6 See Section 4.3.2 for all aspects related to underground primary service lateral connections from overhead lines.

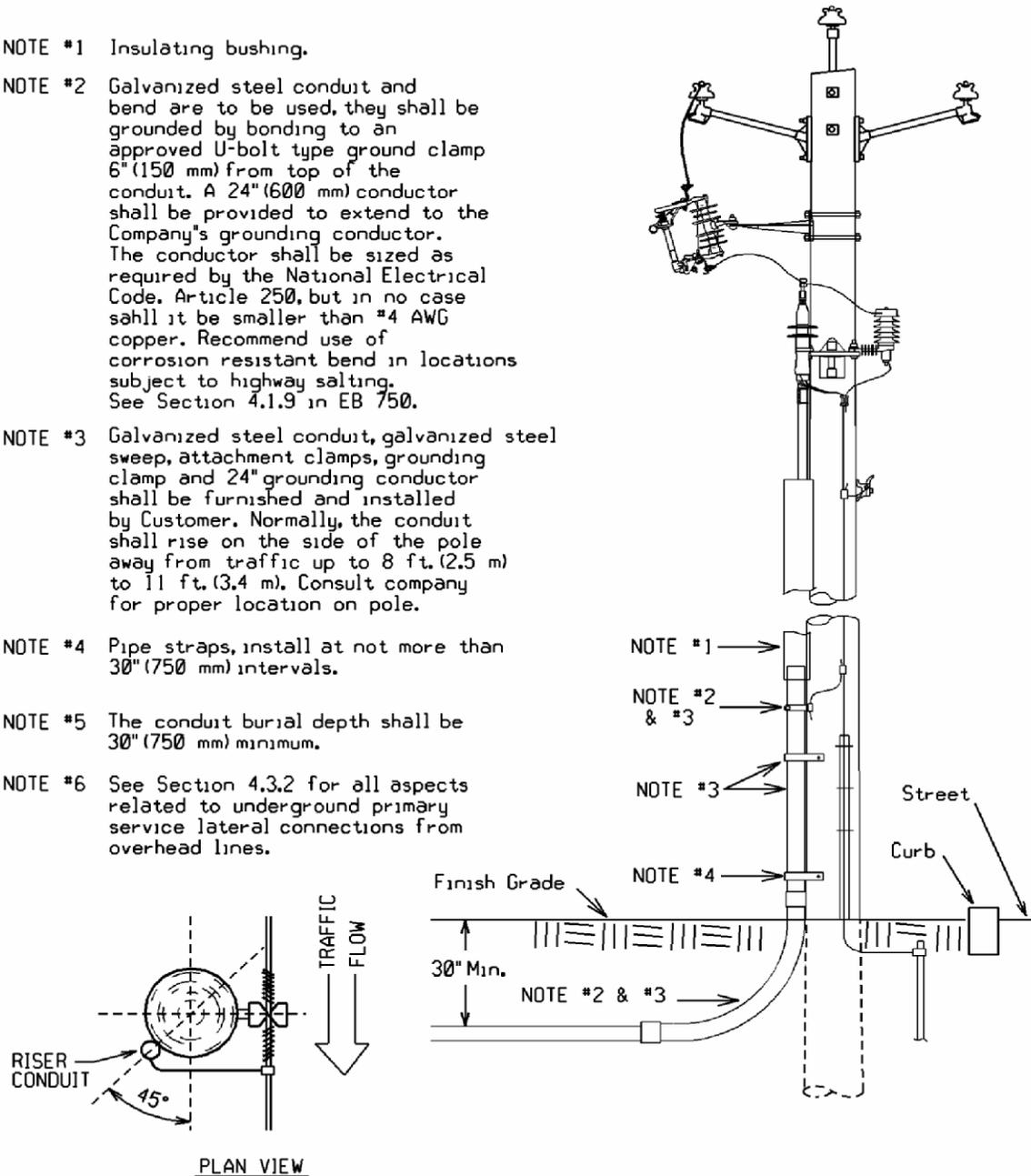
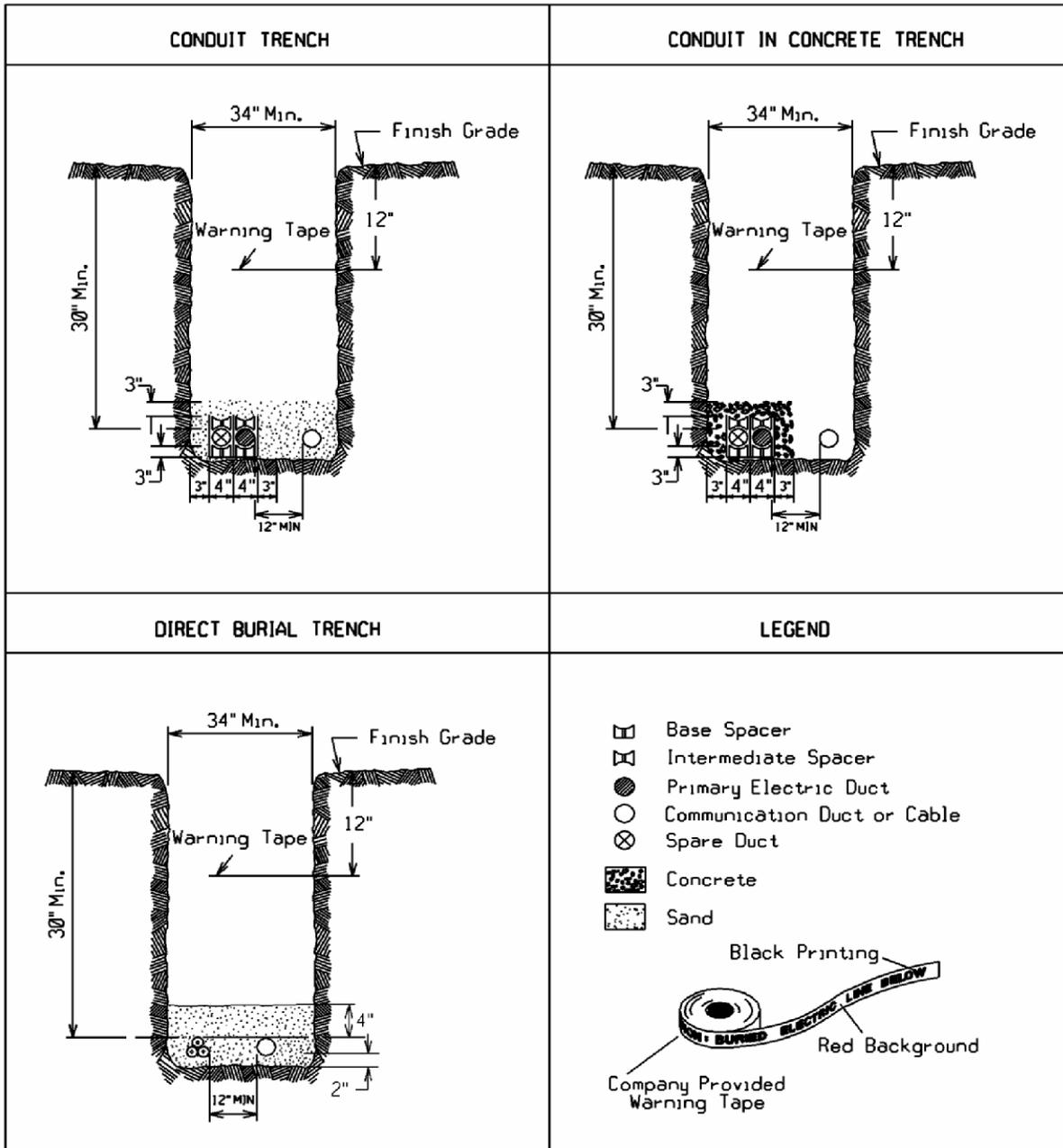


FIGURE 12

Typical Primary Riser Pole Detail



Typical Backfilling Details of Underground Primary Cable And Warning Tape Installation In Trench

FIGURE 13

## TRANSFORMER FOUNDATION INSPECTION CHECKLIST

Do not pour concrete prior to inspection and approval by Company of the pad forming and reinforcement, the subgrade preparation, and the ground grid. Do not back fill after removing the forms prior to pad inspection. Every item listed below must be inspected and checked off by the Customer's qualified installer and provided to the Company.

N ✓ Y ✓

### PRE-INSTALLATION

- Proposed location within 10' of paved way open to vehicular access.
- Proposed location has minimum of 10' clear space in front of transformer doors.
- Proposed location has minimum clearance to buildings, doorways, windows, ventilation ducts, fire escapes, and other combustibles according to Section 5.1 and Figure 2.
- Bollard locations are identified by Company.
- Ground grid installation and two ground rods.
- Approved pre-cast pad installed: Manufacturer \_\_\_\_\_ Model: \_\_\_\_\_

### PRE-POURING (if not using pre-cast pad)

- 12" gravel and 2" sand below pad location.
- Reinforcing bars.
- Concrete forms correct height, size, orientation, opening, etc.
- Concrete forms in correct location.
- Ground grid installation and two ground rods.
- 36" radius at all 90° sweeps into pad stopping 1" above pad.
- Secondary sweeps in place and proper number.

### AFTER POURING (if not using pre-cast pad and after removing forms and prior to backfilling)

- Pad correctly formed and 10" high.
- Curing time achieved according to Concrete Supplier's Specifications
- ¾" chamfer along the edges.
- Sweeps 1" above pad.

### AFTER BACKFILLING

- 6" protective bollards are correctly installed.
- Pad 5" above final grade.
- Pad has 10' of clear space in front of transformer doors, is 10' from an accessible paved way and has the minimum clearance to other structures.

#### NOTES:

Y – Acceptable  
Strikethrough requirement if not applicable.

Performed by: \_\_\_\_\_ signature: \_\_\_\_\_ Date: \_\_\_\_\_  
Name (Customer's qualified installer.)

Installer Company Name: \_\_\_\_\_ Address: \_\_\_\_\_

Witnessed by: \_\_\_\_\_ signature: \_\_\_\_\_ Date: \_\_\_\_\_  
Property Owner Name

**Figure 14**

## TRANSFORMER SECONDARY CONNECTION CHECKLIST

Every item listed below must be inspected and checked off by the Customer's qualified installer and provided to the Company.

N ✓ Y ✓

### PRE-INSTALLATION

- - Service configuration and service equipment ratings and overcurrent device meets accepted design by the Company.
- - Number of conductor sets and connectors meet Sections 4.4.1 and 4.4.3.

### PRE-ENERGIZATION

- - Service cable conductors labeled for phase identification.
- - Service cable conductors continuity tested for proper phase connections to service equipment.
- - Service cable conductors megger tested for insulation integrity acceptance.
- - Company bushing current transformers installed for hot sequence metering where required.
- - Company current transformers installed in cabinet for hot sequence metering where required.
- - Secondary cable connectors torqued (*and taped, only if required by company*).
- - 3<sup>rd</sup> Party Electrical Inspection Approval Certificate provided to Company for the entire service connection according to Section 1.8 of ESB 750.
- - Ground grid resistance test provided to Company according to Section 6.3.
- - Company notified of Customer's desired energization schedule.

### **NOTES:**

Y – Acceptable

Strikethrough requirement if not applicable.

Performed by: \_\_\_\_\_ *signature:* \_\_\_\_\_ Date: \_\_\_\_\_  
Name (Customer's qualified installer.)

Installer Company Name: \_\_\_\_\_ Address: \_\_\_\_\_

Witnessed by: \_\_\_\_\_ *signature:* \_\_\_\_\_ Date: \_\_\_\_\_  
Property Owner Name

**Figure 14** (cont'd)

**SUPPLEMENT TO**  
**SPECIFICATIONS FOR**  
**ELECTRICAL INSTALLATIONS**

**OPERATION & MAINTENANCE**  
**REQUIREMENTS**  
**FOR SERVICES ABOVE 600 VOLTS**

**ELECTRIC SYSTEM BULLETIN No. 755**

**JUNE 2003**

(Supersedes all previous issues of ESB 755.)

**Niagara Mohawk**

A **National Grid** Company



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### **1.0 INTRODUCTION**

#### **1.1 PURPOSE**

1. The Company's Tariff, PSC No. 207, states that the Company is not responsible for the adequacy or safety of the Customer's equipment or wiring. Further, the Company reserves the right to discontinue service whenever the Customer fails to maintain such equipment and wiring in a safe and adequate condition or fails to utilize electricity in such a manner as to avoid interference with the service furnished by the Company to other customers, or with the use of service by the Customer or others.
2. This Supplement to **Electrical System Bulletin (ESB) #750** and to **ESB's #752, #753, #756A, #756B** and **#758** provides general operation, maintenance and repair requirements and recommendations for a Customer who is supplied by a Company designated voltage in excess of 600 volts.
3. It is important that the Customer and their engineer or contractor obtain and refer to the Specifications for Electrical Installations (**ESB #750**, latest revision) and applicable supplement (**ESB #752** or **#753** or **#756A** or **#756B** or **#758**) in conjunction with this supplement.

## 1.2 SCOPE

1. These requirements are essential to maintain satisfactory service compatible with the electrical supply to the Customer and to others served by the Company System.
2. This bulletin does not cover the Customer's complete electrical installation maintenance requirements, but concern only those points in which the Customer and their qualified electrical contractor and the Company have a mutual interest.

## 1.3 DEFINITIONS

**Notes:** (1) The following are terms defined as used in this publication.

- (2) For other definitions refer to the "**Specifications for Electrical Installations**" (ESB#750), Section 2.

"**Controller**" is the Company's designated person controlling the opening and closing of the Company's supply circuits.

"**Designated Person**" refers to the National Electrical Safety Code term used in NESC Rule 442.

"**Qualified Persons**" refers to the National Electrical Code and National Electrical Safety Code definitions of "qualified person" and "qualified".

## 1.4 REFERENCES

1. Applicable standards for maintenance, operation, and safety of Customer-owned high voltage installations include, but are not limited to:
  - NETA-MTS "Maintenance Testing Specifications for Electrical Power Distribution Equipment and Systems"
  - NFPA 70B "Recommended Practice for Electrical Equipment Maintenance"
  - NFPA 70E "Electrical Safety Requirements for Employee Workplaces"
  - IEEE/ANSI C2 "National Electrical Safety Code"
  - IEEE Std 902 "IEEE Guide for Maintenance, Operation, and Safety of Industrial and Commercial Power Systems"
  - IEEE Std 1048 "IEEE Guide for Protective Grounding of Power Lines"
  - OSHA 29 CFR 1910, Subpart R, Special Industries, Section 269 – Power Generation, Transmission and Distribution Installations
  - OSHA 29 CFR 1910, Subpart S, Electrical, Section 301 – Electrical Utilization Equipment
2. Supplemental Company Specifications include:
  - ESB No. 752 - Service above 15,000 volts
  - ESB No. 753 - Primary Meter Pole
  - ESB No. 756A - Parallel Generation Requirements – Covered by the NYS Standard Interconnection Requirements
  - ESB No. 756B - Parallel Generation Requirements – Requirements Over 300kVA or Where Interconnected Over 15kV
  - ESB No. 758 - Primary Service to Metal Enclosed Gear

All ESB's are available at <http://www.NiagaraMohawk.com/electricalspecifications>

## 2.0 GENERAL

### 2.1 CUSTOMER'S RESPONSIBILITY

1. The Customer's electric service equipment and its installation shall conform to the Company requirements and specifications as applicable in the Purpose section above.

2. The Customer shall be responsible to have all electrical and physical design documents prepared and updated by a design professional, in accordance with **Section 1.7** of **ESB #750**, and as further detailed in either **ESB #752** or **#753** or **#756A** or **#756B** or **#758**.
3. The Customer has the responsibility to provide qualified persons to operate and maintain, in good working order, their service equipment or generation under their ownership that is directly involved with the Company's system, see the Company's **ESB #750** and either **ESB #752** or **#753** or **#756A** or **#756B** or **#758**.
4. The Company requires the Customer to perform protective device calibration and functional testing by qualified persons of any device that operates the Customer's or Generator-owner's main disconnect and overcurrent device necessary for protection coordination with the Company's electric supply connection.
5. If relay settings are altered, they shall be reviewed by the Company for acceptance. Unauthorized setting changes place the Company's system and the Customer's facility at risk.

## **2.2 COOPERATION**

1. The information the Customer or their qualified electrical contractor furnishes to the Company under this bulletin shall be in writing.
2. It is the responsibility of the Customer to ensure the test results meet manufacturer requirements. Receipt of such information by the Company shall not be construed to be an approval of the Customer's facility in regard to its overall safety or adequacy.
3. The Company will advise the Customer concerning any contribution which may be required of them for materials supplied and work performed by the Company associated with the Customer's maintenance or repair activity in accordance with the Company's filed tariff.

## **3.0 COMPLIANCE**

### **3.1 INSPECTION**

1. Refer to **ESB #750, Section 1.8** for inspection requirements for new or changed electrical facilities. For these, the Customer must obtain approval from a certified inspection agency.
2. The Company reserves the right to have an authorized representative examine the Customer's installation for equipment having an effect on the Company's system before it is energized to insure compliance with Company service requirements.

### **3.2 OPERATING PROTOCOL WITH THE COMPANY'S SUPPLY**

1. The Company shall supply operating instructions to the Customer which define the switching protocol for all equipment of mutual interest with the Company. The operating instructions will be based on the following information from the Customer:
  - Contact personnel and telephone numbers and
  - Single-line diagram described in either **ESB #752** or **#753** or **#756A** or **#756B** or **#758** of the Customer's primary and secondary equipment directly involved with the Company's system.
2. The Customer is responsible for maintaining this information up-to-date and notifying the Company of any changes. These operating instructions shall be followed in all operations involving the Customer's service equipment directly involved with the Company's system.
3. The Customer is responsible for developing operating instructions for the balance of their electrical system.

4. Customer personnel or equipment shall not come closer than the following distances to any Company-owned energized overhead conductor: (From New York State High Voltage Proximity Act - 1989.)

600V ≤ 50kV	>50kV ≤ 115kV	230kV	345kV
10 ft.	15 ft.	17 ft.	20 ft.

- 3.2.4.1 No activities shall be permitted which compromise the electrical or structural integrity of the overhead electric facilities.
- 3.2.4.2 No activities shall be permitted which prevent or inhibit the Company from exercising reasonable ingress and egress along the Company's Right-of-Way.
5. At the Customer's request, the Company will provide isolation and grounding guarantees at the Customer's service disconnect or Company isolation point on the supply line ahead of the Customer's service equipment. However, the Customer's qualified personnel shall not rely on the Company's grounding provisions for their safety. The Customer's qualified personnel shall supply their own protective grounds and/or follow their own safety procedures to work on their equipment.
6. The Company will provide nomenclature for Customer's labeling of the main disconnect switch and other electrical equipment referred to in the Company's switching instructions. The Customer shall make provisions for and maintain the labeling of this equipment and any necessary Company mark-up tag holder.
7. NO WORK SHALL BE PERFORMED ON THE MAIN DISCONNECT SWITCH WHILE THE COMPANY'S INCOMING LINE IS ENERGIZED. Notify the Company and arrange for an interruption and a guarantee before doing any work at or near this section. In addition, a grounding guarantee may be requested.
8. The Customer's qualified person(s) shall operate within established Company mark-up rules in any switching operations with the Company for their equipment that both the Company and the Customer have a mutual interest. Customers supplied at 115kV and higher voltage service shall provide the Company with a minimum 7 working day advance written notice for switching requests.
9. The Customer shall recognize and abide by the Company's mark-up rules. The Customer shall conduct their switching based on their switching practices insuring that the Company's mark up is not jeopardized or modified.

Company mark-up tags are used to prohibit operation of electrical devices and indicate that employees are at work. Equipment shall be placed in their protective position and rendered inoperable by locking and tagging. Tags alone may be used when the equipment can not be rendered inoperable by locking. The Customer shall never operate a device that bears a Company mark-up tag.

### 3.3 NON-COMPLIANCE

Failure to adequately operate, maintain or repair electric service facilities as described in this bulletin will subject the Customer to the terms and conditions of the Company's tariff, PSC No. 207, and individual interconnection agreements resulting, ultimately, in discontinuance of service. See **Sections 3 and 11 in ESB #750.**

## 4.0 ROUTINE MAINTENANCE - CUSTOMER'S SERVICE FACILITIES

### 4.1 GENERAL

1. Proper preventative maintenance and/or diagnostic testing are important to the operation of the equipment and shall be performed in accordance with manufacturer's instructions as a minimum.

2. See **Section 1.4** “References” for publications that could be helpful in setting up a maintenance program along with equipment manufacturer instructions.
3. The Company does not provide any spare parts for the Customer's installation. The Customer should determine their inventory of spare parts for fuses, circuit breakers, fault interrupters, switchgear, and other electrical equipment essential to minimize their interruption time.
4. The Customer shall ensure their service equipment, including fuses, is suitable for the available supply characteristics, such as device interrupting capability. Upon request, the Company can provide the Customer the available system characteristics at the service point.
5. Periodic verification of ground grid integrity and ground grid resistance to remote earth is recommended to ensure safe step and touch potentials within the Customer’s facility.

#### **4.2 CUSTOMER’S QUALIFIED PERSONNEL AND TOOLS**

1. It is the Customer’s is responsibility to provide qualified personnel, properly equipped with safety equipment tested for the circuit voltage involved, to perform all switching or other work on their facility.
2. The Company does not provide any operating tools or test equipment for the Customer's use. The Customer shall provide their own operating equipment such as tongs, insulating switching sticks, insulated rubber gloves, grounds, ground bails, studs and grounding sticks; voltage detection equipment, etc. needed for the safe performance of operating functions. This operating equipment shall be properly maintained and tested according to the manufacturer's instructions.

#### **4.3 COMPANY-CONTROLLED SPACES IN CUSTOMER ELECTRICAL FACILITIES**

1. Line terminations and the metering transformer compartments of the Customer's switchgear will be locked by the Company when the Company's work is completed and marked clear with the Company’s Controller.
2. Customer access: The Company's control of electric spaces in Customer-owned electric facilities is for the sole purpose of protecting the integrity of the Company's energy supply and security of the utility metering equipment.
  - 4.3.2.1 See **Section 3.2** for isolation and grounding guarantees at the Customer's service disconnect or Company isolation point on the supply line ahead of the Customer's service equipment.
  - 4.3.2.2 When the Customer does not require a guarantee on the supply line and needs access to Company-controlled electrical spaces for their maintenance purposes, the Company in its sole judgment may determine the ability to grant access to the Customer for the duration established by the Company. When granted, the Company will witness the Customer's placement of their lock immediately after the removal of the Company's lock. Upon notification by the Customer that their work is complete, the Customer shall relinquish access back to the Company and the Company's lock shall be placed immediately upon the removal of the Customer's lock. In each case the transfer shall occur in the presence of both parties. The Company will check its electrical equipment for any signs of tampering.
  - 4.3.2.3 At the sole discretion of the Company, access may be granted to energized spaces controlled by the Company. Such access requires the execution of the agreement in **Exhibit 1**.
  - 4.3.2.4 In the event that the required access is of short duration and the Company's representative remains on site, to avoid a second trip, it is understood they are doing so without any supervisory or oversight capacity relative to the Customer.

#### 4.4 PROTECTIVE RELAY TESTING

1. The Customer's qualified personnel shall perform calibration and functional checks on all Company-designated protective relay devices (typically 50/51 and 50/51N for load customers and for those with parallel generator(s) including 27, 59, 81, and if any 51V and 64 devices are used). It is the Customer's responsibility to determine suitable relay maintenance intervals based on manufacturer's instructions and site specific criteria such as temperature, dust, age of the relays, etc. However, the Customer shall not exceed the following maximum intervals:
  - Microprocessor Relays: 6 years
  - Electro-mechanical Distance/Directional Relays (e.g., 21, 32, 67): 4 years
  - Electro-mechanical Overcurrent/Over/Under Voltage Relays (e.g., 50/51, 27, 59): 6 years
  - Certain relaying schemes require 2-year maintenance intervals due to NERC regulations. The Customer shall be informed separately by the Company if they fall under this requirement.
2. Protective Devices associated with NY SIR Distributed Generation projects:  
Protective device maintenance criteria are identified in a test plan provided by the Customer and accepted by the Company. The execution of the plan is by the Customer's qualified person. The Customer shall maintain logs of their periodic verification checks of the type tested devices according to the PSC's required interval and produce documentation to the Company upon request. See **ESB # 756A**.

#### 4.5 AFFIRMATION OF MAINTENANCE RECORDS

1. Copies of test records of major station equipment and protective devices, for example breaker, transformer, outdoor switches, and relays, shall be maintained by the Customer on their premise and be made available to the Company upon request.
2. In addition, the Customer shall submit a written affirmation to the Company that indicates, as a minimum, the recent date and the description of the maintenance activities specified in **Section 4.5.1** above that were performed and by whom including installation document references. See **Exhibit 2** for a sample letter to be used and signed by the Customer when reporting any maintenance performed to the Company.
3. All written affirmations shall be sent to the Company's assigned Account Manager. If written affirmation is not received within 30 days after completion of the verification activities, it is the Company's intent to enforce this requirement as specified in **Section 3.3** above.
4. If changes were noted by the Customer in their written affirmation, the Company will review the changes for acceptance in accordance with the ESB 750 series bulletin in effect.

#### 5.0 REPAIR OF CUSTOMER'S SERVICE FACILITIES

##### 5.1 NOTIFICATION

1. The Customer shall notify the Company for any repair work associated with their fuse, switch, breaker, high voltage fault interrupter, transformer, and relay devices being planned for their electric service facilities with a schedule.
2. The Customer shall follow the operating protocol and isolation and grounding guarantee requirements in **Section 3.2** for repair activities with their electric service facilities.

## 5.2 PRE-ENERGIZATION REVIEW

1. In the mutual interest to protect the Customer and the Company, the Company may require the submittal of satisfactory equipment test results according to manufacturer specifications.
2. The Customer's outdoor substation physical protection shall be in place in accordance with applicable codes and local requirements, i.e., fence, gates, signs, locks, grounding system. See the Company's ESB #752 or #758.
3. Modifications to Company-designated protective relay settings shall receive prior acceptance from the Company. Once accepted, the Company shall be provided two (2) weeks advance written notice by the Customer to witness calibration of the designated devices before energization.
  - 5.2.3.1 The Company at its sole discretion may review the test results performed by the Customer's qualified person for this verification on Company-designated protective equipment owned by the Customer. The Company's assurance of the Customer's field verification for non-type tested protective devices designated for utility interconnection will include at least the following:
    - (1) Confirmation of the Company's accepted relay settings,
    - (2) Functional checks of the designated relays,
    - (3) Customer supplied documentation:
      - For replaced instrument transformers, the relaying current transformer saturation curves from the manufacturer for protective relay circuits affecting the designated protective devices.
      - Letter stating that all Company-designated protective device control wiring, including the wiring from the instrument transformers, has been verified against the design drawings.
      - Letter stating the most recent calibration and test performed on protective relays affecting the designated protective devices.
  - 5.2.3.2 The Customer's qualified person shall submit to the Company a written summary of the satisfactory test results within five (5) business days after energization. Refer to **Exhibit 2** for a sample letter to affirm the results.
4. The Customer shall submit any proposed main fuse rating change to the Company for review and acceptance. The Customer shall ensure fuses used as the main protective device will be coordinated with their system and shall not be greater than the Company-specified maximum rating.
5. If repairs necessitate the alteration or replacement of electrical equipment or relaying schemes, the Customer shall provide documentation for review and acceptance by the Company based on the applicable ESB 750 series bulletins prior to re-energizing their facilities.

## 5.3 PROJECT MANAGEMENT

1. All outside communications to and from the Company, rate discussions, billing, energization coordination, etc. shall be directed through the Company's assigned Account Manager.
2. Technical aspects related to the Company's service requirements above 600 volts shall be directed through the Company's division Customer Facilities Engineer.

**EXHIBIT 1: Sample Customer form for access to energized spaces that are controlled by the Company**

**Niagara Mohawk**

A **National Grid** Company



**Access to an Energized High Voltage Space Controlled by Niagara Mohawk**

XYZ, Contractor, has requested that Niagara Mohawk, NM, remove the lock from the energized electrical space(s) located on the premises of ABC Company 123 ABC Avenue NYS City, NY 14208. Before NM will do so, Contractor shall certify that all persons who will work at this premise will be properly trained for the work and will be properly supervised during the work. Contractor shall also certify that, upon removal by NM of NM's lock, Contractor will immediately install Contractor's own lock and will continuously supervise admittance to the vault until the re-installation by NM of NM's lock.

SO CERTIFIED, this \_\_\_\_\_ day of \_\_\_\_\_, \_\_\_\_\_

CONTRACTOR \_\_\_\_\_ (See Note)

BY \_\_\_\_\_

Name \_\_\_\_\_

Officer Title \_\_\_\_\_

Date \_\_\_\_\_

(Note: Officer or owner of Contractor shall insert full corporate name and sign.)

## **EXHIBIT 2: Sample Customer Letter of Affirming Preventive Maintenance of Service Equipment Served Above 600 volts**

<<Customer's letter head>>

Subject: Preventive Maintenance of \_\_\_kV Service Equipment at \_\_\_\_\_

Dear Niagara Mohawk Account Manager:

We have completed our preventive maintenance of the following equipment in accordance with your Company's service requirements and attest that the equipment is acceptable according to the manufacturer's instructions and specifications: <<include the following items as applicable>>

- outdoor gang-operated main disconnect switch
- metal-enclosed switchgear
- power transformers
- circuit breakers
- high voltage fault interrupters (i.e. circuit switchers)
- utility-designated protective relay devices (list as applicable 50/51 and 50/51N for load customers or for those with parallel generator(s) including 27, 59, 81, and if any 51V and 64 devices are used)

<<if applicable>>We are providing the following documentation in support of the accepted relay tests:

- certified calibration sheets of the settings as left on each device,
- updated short circuit and protective device coordination analysis of the high voltage overcurrent protective device and transformer protection system, and
- record of relaying instrument transformer secondary current and voltage checks.

<<where applicable>>In addition, we have verified for our outdoor substation:

- the integrity of the station ground grid meets the required ground grid resistance of \_\_\_ ohms for safe step and touch potentials within the station and
- the physical protection is in place in accordance with the utility service requirements and applicable codes and local requirements, i.e., fence, gates, signs, locks, grounding system.

Refer to the enclosed functional single-line diagram for the above equipment maintained and tested.

Our next planned preventive maintenance on this equipment is scheduled for \_\_\_\_\_ and we will apprise you in this same manner when that time draws near.

<<Customer Signature>>

<<Officer title>>

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*Supplement to*

# Specifications for Electrical Installations

**Requirements for Parallel Generation Connected  
to a National Grid Owned EPS**

Electric System Bulletin No. 756

**June 2017, Version 3.0**

(Supersedes all previous versions of ESB 756)



## **PREFACE**

ESB 756-2017 references all requirements for parallel generation connected to National Grid facilities located in transmission jurisdictions in Upstate New York, Massachusetts, New Hampshire, Rhode Island, and Vermont and for distribution jurisdictions in Upstate New York, Massachusetts, and Rhode Island.

This supplement and its appendices are available on National Grid's website at <http://www.nationalgridus.com/electricalspecifications> and in printed form by contacting either of the National Grid Call Centers in Massachusetts or New York (see inside cover of ESB 750 for Customer Service Center telephone numbers). However, since printed copies may not reflect the latest updates, please refer to National Grid's website for the latest authorized versions.

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## 1.0 INTRODUCTION

### 1.1 PURPOSE

The purpose of this National Grid Electric System Bulletin (ESB) is to:

1. Provide general requirements and recommendations for all generators connected in parallel with the electric power system (EPS) operated by National Grid (the “Company”). 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 Electric System Bulletins, the most current version of ESB 756 is available electronically at: [www.nationalgridus.com/electricalspecifications](http://www.nationalgridus.com/electricalspecifications).
3. Ensure that 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 interconnecting customers (IC) to the applicable Federal Energy Regulatory Commission (FERC) or state-specific tariff regulations pertaining to parallel generators.

### 1.2 SCOPE

1. This ESB addresses FERC-jurisdictional interconnections, where the generator wishes to interconnect to:
  - A transmission system owned by National Grid that is administratively controlled by a regional independent system operator (“Regional ISO”);

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- A distribution or sub-transmission line owned by National Grid (which is presently interconnected to a third party energy supplier or generating facility selling power into the wholesale market) for the purpose of selling power into the wholesale market.
2. This ESB also addresses state-specific requirements pertaining to parallel generators. These are contained in individual appendices at the end of this document.

### **1.3 GENERAL RULES, AND CODES, STANDARDS AND REFERENCES**

1. All new parallel generator installations require an interconnection study, done at customer expense, to determine site-specific requirements (i.e. supply voltage, interconnection and service arrangement, location, and generation intent). Generation intent, in this context, refers to its end use being either: (1) total generator output energy for internal use, i.e. peak shaving, (2) sale, or (3) a combination. Additional interconnection requirements for new generation connections to the 115 kV and above in New York and 69 kV and above in New England transmission system shall conform with applicable requirements of the NY or NE ISO Tariffs, respectively. Note that this could apply at lower system voltage levels depending on whether the Generator-Owner or IC is selling power into the market.
2. For electrical specifications not covered by this document, the Customer shall refer to the Company's other Electric System Bulletins, see [www.nationalgridus.com/electricalspecifications](http://www.nationalgridus.com/electricalspecifications).
3. Load customers (end-user facilities) wishing to connect to the Company's transmission supply system should consult the Company's ESB 750 Series for Upstate New York, Massachusetts, New Hampshire and Rhode Island. In addition, consult the Company for any questions not addressed by those documents.
4. Those wishing to establish "transmission facility interconnections" with National Grid's transmission supply system should consult the Company's Transmission Planning Department. Requirements for new transmission facility interconnections to the 115 kV and above in New York and 69 kV and above in New England transmission system shall conform with applicable requirements of the NY or NE ISO Tariffs, respectively.
5. The Generator-Owner's or IC's facility shall conform to the latest revision of all local, state and federal codes and national standards that apply; individual state Independent System Operator; Northeast Power Coordinating Council, Inc. (NPCC), and NERC, FERC, or successor organizations associated with the operation of such systems or entities.
6. The Generator-Owner's or IC's facility shall also conform to any applicable requirements of state public utility regulatory commissions and any local, state, federal and/or other agencies from which a review, approval, or a permit is required.
7. These requirements govern the operation of generation in parallel with the Company's EPS. They concern only those points in which the Generator-Owner or IC and the Company have a mutual interest in the generator facility's or premises' wiring service connection to ensure safety to the public and the Company's employees as well as satisfactory operation, compatibility, and reliability with the electrical supply to others served by the Company's EPS.
8. Regarding coordinated joint studies of new facilities and their impacts on the Company's interconnected transmission systems, the NY or NE ISO, in accordance with the applicable sections of their respective tariffs, shall coordinate the conduct of any studies required to determine the impact of the Interconnection Request on Affected Systems with Affected Transmission Owners and, if possible, include those results (if available) in its applicable interconnection study within the time frame specified in these procedures. The Regional ISO will include such Affected Transmission Entities in all meetings held with the Interconnection Customer as specified in the respective Tariffs. Notification of new or modified facilities to those parties responsible for the reliability of the interconnected transmission systems will occur as soon as feasible.

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9. The voltage level, and MW and MVAR capacity or demand at the point of connection shall be addressed in a System Impact Study, which shall:
  - a. Consist of a short circuit analysis; a stability analysis; a power flow analysis; voltage drop and flicker studies; protection and set point coordination studies; and grounding reviews, as necessary.
  - b. State the assumptions upon which it is based, state the results of the analyses, and provide the requirement or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection.
  - c. Provide a list of facilities that are required as a result of the Interconnection Request and non-binding good faith estimates of cost responsibility and time to construct.
10. Distribution System impact studies shall incorporate a distribution load flow study, an analysis of equipment interrupting ratings, protection coordination study, voltage drop and flicker studies, protection and set point coordination studies, grounding reviews, and the impact on electric system operation, as necessary.
11. Maintenance coordination and operational issues such as abnormal frequency and voltages shall be addressed by the Regional ISO.
12. Inspection requirements for existing or new facilities, and communications and procedures during normal and emergency operating conditions are addressed in ESB 755, "Operation and Maintenance Requirements For Services Above 600 Volts".
13. Any subsequent sale of generation ownership, which separates it from the remainder of a Customer's facility, requires the new Generator-Owner or IC to establish a separate interconnection for the generation.
14. Applicable national standards may include:
  - IEEE 519 "Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems"
  - IEEE 1547 "Standard for Interconnecting Distributed Resources with Electric Power Systems"
  - NFPA 850 "Recommended Practice for Fire Protection for Electrical Generating Plants and High Voltage Direct Current Converter Stations"

#### **1.4 DEFINITIONS**

**Company** is National Grid

**Company EPS** refers to the electric power system owned, controlled, or operated by the Company and used to provide transmission or distribution services to its customers.

**Generator interface point** is the point of electrical connection of the parallel generator to the premise wiring.

**Generator-Owner** refers to any Non-Utility Generator even though they may also actually take electric service from the Company.

**Interconnection Facility** refers to those facilities necessary to effect the transfer of electricity from the parallel generator at the service point into the Company EPS.

**Interconnection Point** is where the interconnection facility connects to the Company EPS.

**Interconnection System** is the collection of all interconnection equipment and functions, taken as a group, used to interconnect a DR unit(s) to the Company EPS.

**Islanding** is generation serving utility load (or lines) without a synchronizing utility source connected.

**ISO secured transmission system** refers to delivery voltage systems as defined by the NPCC and controlled by a Regional ISO.

**Isolation** is where separation of electrical points of contact where interconnection may occur is at least 100 feet apart.

**Parallel generator** is defined as generation connected to a bus common with the Company EPS.

**Production Facility** refers to the Generator-Owners' or IC's (producers') parallel generator facilities. It shall include all facilities and equipment up to and including the Production Facility's high voltage side generator transformer disconnect or switches.

**Wholesale Delivery Point** shall mean the point on the Company EPS where the IC makes capacity and energy available, as indicated in the interconnection agreement.

## 2.0 REVISION HISTORY

<u>Version</u>	<u>Date</u>	<u>Description of Revision</u>
1.0	06/01/07	Initial version of new document superseding all previous revisions of ESB 756.
1.1	09/06/11	September 2010 ESB 750 Series Errata changes.
2.0	05/11/12	Revised ESB 756 Appendix C and added version numbers to appendices.
2.1	08/22/12	Revised ESB 756 Appendix D.
2.2	09/22/14	Editorial to ESB 756 Appendix A and Revised ESB 756 Appendix B.
2.3	09/08/15	Revised ESB 756 Appendix C.
3.0	08/03/17	June 2017 major revision of Appendices A – D and deletion of E.

## LIST OF APPENDICES TO ESB 756

***APPENDIX A: Requirements For Parallel Generation Connected to National Grid Facilities in New York, Massachusetts, Rhode Island, New Hampshire, and Vermont Not Applicable to State Regulatory Distributed Generator Interconnection Requirements version 2.0***

***APPENDIX B: Distributed Generation Connected To National Grid Distribution Facilities Per The New York Standardized Interconnection Requirements, version 4.0***

***APPENDIX C: Distributed Generation Connected To National Grid Distribution Facilities Per The Massachusetts Standard for Interconnecting Distributed Generation, version 4.0***

***APPENDIX D: Distributed Generation Connected To National Grid Distribution Facilities Per The Rhode Island Standards for Connecting Distributed Generation, version 3.0***



**Electric System Bulletin No. 756 Appendix A:**

**Requirements For Parallel Generation  
Connected to National Grid Facilities in New York,  
Massachusetts, Rhode Island, New Hampshire, and  
Vermont Not Applicable to State Regulatory  
Distributed Generator Interconnection Requirements**

**June 2017 version 2.0**

ESB 756 Appendix A is part of the ESB 750 series

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## PURPOSE

1. Electric System Bulletin (ESB) 756 Appendix A covers requirements for interconnecting generation facilities in parallel with National Grid’s (the “Company”) transmission and distribution electric power systems (EPS) where owned and operated in New York, Massachusetts, Rhode Island, New Hampshire, and Vermont.
2. ESB 756 Appendix A does not cover the New York State Standardized Interconnection Requirements and Application Process For New Distributed Generators 5 MW or Less Connected in Parallel with Utility Distribution Systems (NY SIR), or Massachusetts Standards for Interconnecting Distributed Generation (MA SIDG), or Rhode Island Standards for Connecting Distributed Generation (RI SCDG); see ESB 756 Appendix B, or Appendix C, or Appendix D, respectively.
3. This ESB supplements the Company’s ESB 750, Specifications for Electrical Installations, and various technical federal and state transmission operator jurisdictional requirements (FERC, NYISO, and ISO-NE) to provide general requirements, recommendations, and assistance to customers (i.e., Generator-Owners or interconnecting customers (IC)) regarding generator facility systems connected in parallel to the Company’s EPS.
4. ESB 756 and this Appendix A are available on the Company’s website at <http://www.nationalgridus.com/electricalspecifications> and in printed form by contacting either of the Company’s Call Centers in Massachusetts or New York (see inside cover of ESB 750 for Customer Service Center telephone numbers). However, since printed copies may not reflect the latest updates, please refer to the Company’s website for the latest authorized versions.

## SCOPE

1. This Appendix A to ESB 756 is provided to assist a Generator-Owner or IC desiring to interconnect a generator facility to National Grid’s EPS to meet requirements of 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 to only those points in which the Generator-Owner or IC and the Company have a mutual interest in the generator facility’s or premises’ wiring service connection to ensure safety to the public and the Company’s employees as well as

satisfactory operation, compatibility, and reliability with the electrical supply to others served by the Company's EPS. This includes, but is 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 generator 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 respective jurisdictional electricity tariffs. See 90.2(B)(5) in the National Electrical Code® (NEC) and the Company's ESB 750 for more information.

3. These requirements pertain to those types of parallel generation that include merchant power plants, independent power producers (IPP), on-site generators (OSG), and energy storage systems (ESS) including distributed generators (DG) or distributed energy resources (DER), ESS, and microgrids not covered by retail interconnection tariffs, and where DER providers, or DER providers through DER aggregators, sign onto the wholesale or retail tariff with the intent to sell energy or ancillary services to the wholesale or retail generation markets. For wholesale tariff requirements, please refer to the following regional independent system operator ("Regional ISO") websites for the applicable jurisdiction:

NY:

[http://www.nyiso.com/public/markets\\_operations/services/planning/documents/index.jsp?docs=int erconnection-studies/other-interconnection-documents](http://www.nyiso.com/public/markets_operations/services/planning/documents/index.jsp?docs=int%20erconnection-studies/other-interconnection-documents),

[http://www.nyiso.com/public/markets\\_operations/documents/technical\\_bulletins/index.jsp](http://www.nyiso.com/public/markets_operations/documents/technical_bulletins/index.jsp), and

[http://www.nyiso.com/public/markets\\_operations/documents/manuals\\_guides/index.jsp](http://www.nyiso.com/public/markets_operations/documents/manuals_guides/index.jsp)

MA, NH, RI, & VT: <https://www.iso-ne.com/system-planning/system-plans-studies> and

<https://www.iso-ne.com/participate/rules-procedures/operating-procedures/?load.more=1>

4. Where state jurisdictional requirements apply of the NY SIR, or MA SIDG, or RI SCDG, please refer to those retail tariff requirements at the Company's websites for the applicable jurisdiction:

NY: [https://www9.nationalgridus.com/niagaramohawk/business/energyeff/4\\_app-pkg.asp](https://www9.nationalgridus.com/niagaramohawk/business/energyeff/4_app-pkg.asp)

MA: [https://www9.nationalgridus.com/masselectric/home/energyeff/4\\_interconnection-process.asp](https://www9.nationalgridus.com/masselectric/home/energyeff/4_interconnection-process.asp)

RI: [http://www9.nationalgridus.com/narragansett/business/energyeff/4\\_interconnection-process.asp](http://www9.nationalgridus.com/narragansett/business/energyeff/4_interconnection-process.asp)

5. 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 not ordinarily encountered or are not covered by any other regulated requirements, including but not limited to stored energy, regenerative drives used in elevators, and component power inverters used in exercise equipment and any other micro scale type of energy recapture systems.

## 1.0 GENERAL

### 1.1 Permitted Connections

The Company may be able to eliminate the need for a specific study in instances of the basis of the available systems. The Company shall determine the suitability of a given generator connection and its interconnection voltage.

#### 1.1.1 Secondary Grid and Spot Network Areas

For specific technical requirements of parallel generation in secondary grid and spot network distribution systems, see the Company's ESB 756 Appendices B, C, and D. Additionally, the Company's jurisdictional websites for interconnecting generator facilities in each state provide

area maps locating the Company's secondary network service areas to assist the Generator-Owner or IC in determining if the proposed location is served by a distribution secondary network system.

### **1.1.2 Phase Balance and Voltage Tolerance**

The Generator-Owner's or IC's generator facility shall permit equal current in each phase conductor at the service point or point of common coupling (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 EPS facilities and service to others. This design and operating criterion shall be met with and without generation in the Generator-Owner's or IC's generator facility.

The interconnection of the Generator-Owner's or IC's generator facility shall not affect the Company's nominal voltage delivery at the PCC by greater than 3% unless directed by the Company's transmission system operator or Regional ISO. Generator-Owners or ICs proposing parallel generator facility installations must consider that the Company's distribution EPS in rural locations will likely have single-phase loads on feeders that inherently have some unbalance on the main three-phase lines. The Company will specify conditions where volt-VAR control will apply.

## **1.2 Access and Contacts**

1. Authorized Company employees, equipment, and vehicles shall have access to the Generator-Owner or IC facilities and Company's metering equipment at any time without delay.
2. The Generator-Owner or IC shall provide information identifying their contact person(s), addresses and their associated telephone number(s) to the Company.
3. Changes to phone numbers, points of contact, etc., shall be communicated in advance of the actual change with the effective date of change so indicated.
4. The Company will provide the Generator-Owner or IC with phone numbers for the appropriate Company contact(s). (Typically the jurisdictional Customer Service Center for generator facilities interconnected on 15kV or less systems and the jurisdictional distribution system Control Center for large generator facilities interconnected on 15kV and less systems that are wholesale registered and all 1 MW or greater generator facilities interconnected on or above 15kV systems.) Note that 5 MW and above generator facilities in New England require registering information with the ISO-NE regardless of interconnecting voltage.
5. If the Generator-Owner or IC enters a generation market through a DER aggregator with the intent of being dispatched for energy or ancillary services, the Company shall be a party to day-ahead up to real-time dispatch communications to coordinate system interaction.

## **1.3 Design Requirements**

### **1.3.1 General Electrical Issues**

1. Parallel generator facilities connected to the EPS can cause a variety of system impacts including steady state and transient voltage changes, harmonic distortion, and increased fault current levels. Those located individually on higher capacity feeders or circuits may not cause very serious impacts whereas those located on weaker circuits, in aggregation or in special cases (such as lightly loaded networks) can significantly impact the Company's EPS. The interconnection of all parallel generator facilities requires safeguards for synchronization and back-feed situations. Further, from the electric system perspective, the challenges posed by any given parallel generator facility's connection do not diminish significantly with reduction in generator facility size. For this reason, each specific connection must be studied with respect to its size, its type, and the nature of the electric system at the interconnection point. Typically, an interconnection 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. It is the intent of any Company study in accordance with jurisdictional regulatory requirements, when applicable, to avoid negative power system impacts by identifying the particular type of impact that will occur under normal and N-1 conditions and determining the required equipment upgrades that can be installed to mitigate the issue(s).
2. There is a wide range of potential issues associated with the interconnection of generator facilities to the Company's EPS including, but not limited to:
    - Impact on step voltage regulation equipment
    - Increased fault duty on the Company's EPS equipment<sup>1</sup>
    - Interference with the operation of protection systems
    - Harmonic distortion contributions
    - Voltage flicker
    - Ground fault overvoltages
    - Risk of islanding
    - System restoration
    - Power system stability
    - System reinforcement
    - Metering
    - Arc flash
  3. All parallel generation shall be designed to ensure:
    - Capability to synchronize with the Company's EPS,
    - Capability to separate from the Company's EPS upon loss of the Company source,
    - No degradation of the Company's EPS safety and reliability, and
    - All energy supplied to the Company's electrical system shall meet the Company's power quality and transmission system operator requirements.
  4. The Generator-Owner or IC shall be responsible for on-going compliance with regulatory, code, and system design and operating changes pertaining to their installation. This work will be performed at the cost of the Generator-Owner or IC. The Company requires all electrical and physical design documents and submittals in this and related Company bulletins relative to interconnections above 600 volts to be prepared and sealed by a single State-licensed Professional Engineer in the state where the installation is made, who is retained by the Generator-Owner or IC for that purpose.

### **1.3.2 Specific Electrical Issues**

The Company will determine the interconnect voltage and method of interconnection with the system as addressed in various portions of this ESB 756 and the Company's other published ESB's.

In general:

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<sup>1</sup> *The Company's substations and circuit breakers are subject to fault duty limitations. Adding generation to the Company's EPS increases the amount of fault current imposed on substation(s) and equipment located on feeder(s). Exceeding fault duties of equipment and devices at substation(s) and on feeder(s) as a result of generator facilities will not be permitted and alternate methods of interconnection shall be explored or the replacement, at the expense of the Generator-Owner or IC, of "overduty" equipment and devices with those of appropriate ratings and in conformance with the Company's standard design where this limit has been reached (see also Section 3.2.2 in this ESB 756 Appendix A).*

1. The preferred interconnection at 230kV and 345kV is a radial line(s) to ISO-secured transmission system station(s).
2. The preferred interconnection at 23kV up to 115kV is a radial line(s) to a station. Other interconnection alternatives may require installation of a Company three-breaker station.
3. For 69kV and above systems upon written request of the Generator-Owner or IC and execution of a Study Agreement, the Company will investigate the feasibility of a tap only for small generator facilities defined in the FERC Small Generator Interconnection Procedures<sup>2</sup> (SGIP) in the course of conducting the Feasibility Study. This investigative effort will be added to the Feasibility Study and will proceed as follows:
  - 1) To adhere to regulatory timeline requirements, the Company will inform the Regional ISO and the Generator-Owner or IC at the scoping meeting that the three-breaker station will be assumed as the “initial” interconnection to be evaluated in the Feasibility Study’s power flow analyses.
  - 2) The Company will also indicate that as the Feasibility Study’s power flow analyses are underway, a protection engineering analysis will review the feasibility of a tap.
  - 3) If a tap is deemed feasible, the tap configuration will be adopted going forward in the System Reliability Impact Study (SRIS) and Facility Study.
  - 4) If a tap appears not to be feasible or when the Generator-Owner or IC waives a Feasibility Study to proceed directly to a SRIS and Facility Study, then the three-breaker station configuration will be used going forward in the SRIS and Facility Study.
  - 5) Engineering cost estimates will be provided for the system upgrade facilities (SUF) associated with either the tap or the three breaker station.
  - 6) The Generator-Owner or IC will be required to install an interrupting device (e.g. breaker or circuit switcher) at the high side of their generator facility’s generator step-up (GSU) transformer.
  - 7) The Study Agreement’s matrix scope may need to be modified to accommodate the need for a possible tap feasibility review prior to the Generator-Owner or IC and the Company executing either the Feasibility Study or SRIS and Facility Study to begin.
4. The Company transmission system required to accommodate the generation interconnection shall be designed and installed to the Company’s standards and practices, under the review and approval of the Company.
5. Regardless of interconnection voltage, protection schemes and connection arrangements shall be designed to prevent islanding of the generation with a portion of the Company’s supply to other customers.
6. The Company reserves the right to review and approve the ratings and parameters of major electrical equipment supplied by the Generator-Owner or IC, such as, but not limited to: GSU transformers, interrupting devices, relays, and the generator facility with its associated systems. For the purposes of this ESB Appendix A, any reference to generator ratings herein refers to the nameplate rating of the generator facility.
  - For inverter-based generation, this shall refer to the nameplate rating of the inverter(s). De-rating of inverter-based generators shall only be considered if the equipment is provided by the Generator-Owner’s or IC’s manufacturer with a permanent means of reducing the rated output, and so marked with an equipment nameplate stating the de-rated output.

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<sup>2</sup> See <https://energy.gov/savings/interconnection-standards-small-generators> and for descriptions of the named studies and agreements.

- 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.
  - Equipment nameplates shall meet American National Standards Institute (ANSI) standards. De-rating of generator facility equipment shall be evaluated on a case-by-case basis, with consideration given to specific project conditions, and may be accepted at the sole discretion of the Company.
7. The Generator-Owner or IC is solely responsible for the protection of their plant equipment. The Generator-Owner or IC is required to provide electrical equipment and relays with ranges and ratings that will allow proper Generator-Owner or IC relay system coordination with the Company's protective relay systems. Coordination margins and parameters will be determined by the Company.
  8. The Generator-Owner or IC is responsible for the coordination of any Generator-Owner or IC applied over and under frequency or over and under voltage generator tripping with Company specified requirements. The generator facility is expected to remain on line and fully operational following a system excursion within specified parameters. The correct performance of the generator facility's frequency protection relays is critical to system security. Consequently each Generator-Owner or IC will be required to both recalibrate their frequency protection and provide the Company this relay performance documentation.

## **1.4 Types of Generators or Other Parallel Sources**

### **1.4.1 Induction**

1. Reactive power supply for induction generators poses difficult design problems, depending on the generator size.
2. Induction generation over 50kVA require capacitors to be installed by the Generator-Owner or IC. The determination of the size and location of the capacitors shall be proposed by the Generator-Owner or IC and reviewed for acceptance by the Company as part of the System Impact Study. The installation of capacitors at or near an induction generator can cause it to become self-excited, if disconnected from the Company EPS. The additional expense for special protective equipment may favor the use synchronous machines.
3. Starting or rapid load fluctuations on induction generators can adversely impact the Company's EPS voltage. Corrective step-switched capacitors or other techniques may be necessary. These measures can, in turn, cause ferroresonance. Across the line starting of induction motors/generators will be permitted only where inrush current and voltage will not exceed allowable motor start inrush limits and the Company's flicker criteria.
4. Otherwise, protection for induction generation is similar to synchronous generation. Although, doubly-fed induction generators have a different protection scheme a squirrel cage induction generation may be treated as synchronous generator. Synchronizing relays may not be required, but a contact-making tachometer set at synchronous speed may be required.

### **1.4.2 Synchronous**

For synchronous generators, sufficient generator reactive power capability shall be provided to withstand normal voltage changes on the Company EPS. The generator voltage-VAR schedule, voltage regulator, and transformer ratio settings will be jointly determined by the Company and the Generator-Owner or IC to ensure proper coordination of voltages and regulator action. For North American Reliability Corporation (NERC) Standard VAR-001 requirements applicable to a Generator-Owner's or IC's generator facility, the Company will direct the Generator-Owner or IC to have an Automatic Voltage Regulator and Control system to operate in automatic voltage control mode, which will be at a voltage set point provided by the Company to maintain EPS voltages.

### **1.4.3 Inverter Systems**

Direct current generators can only be paralleled with the Company EPS using a synchronous inverter. The design shall be such as to remove this synchronous inverter upon a utility system interruption. Proper harmonic filtering is necessary for inverter systems to minimize harmonic distortion from being introduced into the EPS. Normally these filters are inside the inverters. DG Customers proposing inverter systems shall demonstrate compliance with the Institute of Electrical and Electronics Engineers (IEEE) Standard 1547 with the proposed inverter system being certified and listed as having been successfully tested by a Nationally Recognized Testing Laboratory utilizing Underwriters Laboratories (UL) Standard 1741. Systems that do not utilize such listed inverters shall be required to provide alternate protective relaying systems which provide utility system fault detection and disconnection subject to the Company's review and acceptance.

### **1.4.4 Energy Storage System (ESS)**

Various types of ESS may be considered that connect in parallel to the Company's EPS.

Battery storage is common for DER applications where the primary benefit enables DG sources to be dispatched / adjusted upon request behind the meter (BTM). In these cases, the ESS is charged by the DG system to be available later to dispatch the stored energy when the DG facility is not generating. Customers may apply battery storage where there is no DG facility to take electricity from the Company's EPS as a load during off-peak times when rates are lower, store the electricity, and then use the BTM stored electricity during peak times when rates are higher.

ESS clearly has the potential for significant effect on the load flow of the Area EPS and the overall dispatch characteristics of the network. An ESS can be complemented by "smart inverter" technology at the PCC, which could also affect the EPS. Under such circumstances, it is critical to understand the operating characteristics of the ESS, including import and export times, as well as equipment power ratings and capabilities. Additional information may be required at the time of application for interconnection such as:

- Method of ESS connection whether: (1) ESS directly connected to the Company's EPS; (2) DG and ESS DC coupled; (3) DG and ESS AC coupled; (4) ESS on utility line side of service point and revenue meter; and (5) ESS on load side of service point and utility revenue meter with the premises load, as applicable to the proposal.
- Sequence of operation for the charging and discharging capabilities of the ESS and the maximum ramp rate in Watts/minute.
- Non-UL 1741 listed inverters will require a utility intertie relay with the appropriate IEEE 1547 functions, settings, and islanding protection according to the Company's [ESB 756](#) jurisdictional requirements.
- Service configuration and revenue metering provisions shall meet the Company's [ESB 750](#) and its applicable supplements.

### **1.4.5 Microgrids**

Various types of microgrids<sup>3</sup> may be considered that connect in parallel to the Company's EPS. The U.S. Department of Energy (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.*"<sup>4</sup> Microgrids may be particularly

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<sup>3</sup> See IEEE 1547.4-2011, Guide for Design, Operation, and Integration of Distributed Resource Island Systems with Electric Power Systems, at Section 4.3, for examples of electrical configurations of microgrids; available at [http://grouper.ieee.org/groups/scc21/1547.4/1547.4\\_index.html](http://grouper.ieee.org/groups/scc21/1547.4/1547.4_index.html).

<sup>4</sup> See Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision ("REV Proceeding"), Order Adopting Regulatory Policy Framework and Implementation Plan

appropriate to address resiliency and reliability (*i.e.*, ability to island in the event of an EPS outage). The Company's position<sup>5</sup> is that when a community microgrid serves multiple customers (in contrast to a facility or campus-style microgrid serving a single customer such as a university or a hospital), including residential customers, and operates within the surrounding electric distribution infrastructure, the Company is in the best position to own and properly operate electric distribution facilities within the community microgrid for the public interest in terms of safety, reliability, and resiliency.<sup>6</sup>

#### Facility or Campus-style Microgrid PCC to EPS

Facility or campus-style microgrids have certain characteristics described here, all of which fall under the DOE definition. Such microgrids consist of one or more buildings and the relationship with the connection to the Company's EPS 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 Company.

These facility or campus-style microgrids are premises wiring systems governed by the NEC as adopted by the local jurisdictional authority.<sup>7</sup>

#### Community Microgrid PCC to EPS

A "community microgrid" is one that involves a combination of customers from large commercial and industrial to single residential customers with the following characteristics where the Company exclusively controls the electric distribution facilities within the community microgrid.

- 1) Consist of more than one building and more than one customer on multiple properties in relationship with the service from the Company and containing generation resources that operate in parallel with the Company's EPS during normal operation but are designed to operate detached from the Company's EPS in "island mode" whether the source of power during islanding is DER or qualifying facilities ("QFs"), or a combination of DER and QFs.<sup>8</sup>
- 2) The multiple buildings and multiple customers on multiple properties are connected only through the Company's electric distribution facilities. This means there are no common customer-owned electric distribution facilities or common property ownership.

The Company emphasizes the importance of the compliance of all microgrids with the safety requirements of applicable codes. The utility electric distribution facilities connecting participants

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(issued February 26, 2015) ("REV Track One Order"), p. 109, *where the Commission adopts the DOE definition for its purposes as well.*

<sup>5</sup> *The Company shares the same position with other utilities in New York ("New York Joint Utilities" or "NY JU").*

<sup>6</sup> *See REV Proceeding, Joint Utilities' Response to Notice Soliciting Comments on Microgrids (filed May 1, 2015), p. 6.*

<sup>7</sup> *See NFPA 70-2017, National Electrical Code® (NEC) for installation requirements of premises wiring systems related to microgrids.*

<sup>8</sup> *See IEEE 1547.4-2011, supra n. 7 where community microgrids will only operate in island mode for reliability purposes during system emergencies (e.g., storm outages) or to address a temporary electric grid supply deficit. If the community microgrid is otherwise intended, allowed or encouraged to operate in an island mode for other reasons (e.g., economic), such scenarios should be taken into consideration both when designing the community microgrid, particularly given the complexities of resulting controls schemes, and when drafting the transactional agreements among participants.*

and users in community microgrids are delivery systems governed by the National Electrical Safety Code® (NESC)<sup>9</sup> as adopted by the local jurisdictional authority. The individual customers connected to the community microgrid through the utility's electric distribution facilities have premises wiring systems that are governed by both the NEC, as adopted by the local jurisdictional authority, and the Company's own electric service rules for the safety of users from the hazards of electricity.

The Company must be able to control the isolation of a community microgrid at each PCC if the Company is to be held accountable for the safety and reliability of service within such a microgrid. This isolation can be achieved by visible break disconnect switches, interrupting devices or a combination thereof which can be manually or remotely operated by the Company. DER and QFs, if any, may be permitted to automatically trip a microgrid PCC isolation device in order to island the community microgrid; however, they should be blocked from closing such a device until authorized to do so by the Company's control center. The control scheme that will disconnect and reconnect the community microgrid from the Company's EPS must be reviewed and approved by the Company through an interconnection study (and subsequently memorialized in an interconnection agreement among the parties) and may be subject to witness testing and/or periodic testing as necessary. Other scenarios that may be permitted will each have their own complexities. As such, each community microgrid will require that specific protocols be developed to ensure that customer safety and the overall EPS safety and reliability are not in any way compromised.

Variations of proposed community microgrids from these described in this ESB 756 Appendix A will require prior regulatory and Company review.

#### Common Microgrid PCC Requirements

DER interconnection equipment, protective systems and microgrid controllers at the PCC to the Company's EPS are to be designed and operated according to the Company's requirements and specifications as well as to applicable codes and industry standards. These assets may be owned and operated by customers or third parties. Individual DER facility interconnections subject to specific jurisdiction-applicable electricity tariffs shall comply with those requirements for connecting to the Company's EPS in a microgrid.

## **1.5 Limitations**

### **1.5.1 All Generation**

1. The Company permits the operation of generating facilities in parallel with the Company's EPS, whenever this can be done without adverse effects on the general public, the Company's personnel, and the Company's equipment, in accordance with all applicable laws and regulations. Certain protective devices (relays, circuit breakers, etc.) where specified by the Company shall be installed at any location where the Generator-Owner or IC desires to operate generation facilities in parallel with the Company's EPS. These devices promptly disconnect the Generator-Owner's or IC's generation facilities from the Company's EPS whenever faults or abnormal conditions occur.
2. For DER 50 kW or above (standalone or in aggregate), the Company may limit the operation, or disconnect, or require the disconnection of the DER from a distribution or transmission EPS at any time, with or without notice, in the event of real or predicted abnormal operating conditions, so that the safety and reliability of the EPS is preserved. For planned and scheduled maintenance events, prior notice (typically 48 hours in advance) will be provided by the Company whenever possible.

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<sup>9</sup> See ANSI/IEEE C2-2017, National Electrical Safety Code® (NESC) for installation requirements of utility supply and generation systems related to microgrids.

3. In order to maintain a safe and reliable system, the utility needs to be informed of the current and forecasted operating status of a DER. DER sized 50 kW or greater (standalone or an aggregate) shall notify the utility when disconnecting/reconnecting to the distribution system, regardless of enrollment in any Regional ISO-administered wholesale generation markets. The following are some of the issues considered before accepting generation:
  - 1) Proximity to the Company's circuits.
  - 2) Generation capacity and the load on the Company's circuits during light load conditions.
  - 3) Review of voltage profiles and system thermal limitations provided by the Company's system electric studies.
  - 4) System protection coordination with the proposed generation and prevention of the generator from "islanding."
  - 5) Impact of prime mover.
  - 6) Generator-Owner's or IC's facility ratio of generation to light load.
  - 7) DG saturation on distribution circuits (see ESB 756 Appendices B, C, and D).
4. From the above, the Company will determine the voltage, interrupting ratings, type of equipment and controls needed for proper protection coordination. The Company reserves the right to determine the Generator-Owner's or IC's interconnection voltage.
5. The Company reserves the right to have the Generator-Owner or IC remove their generation from the EPS at any time upon the Company's request. Normally, such requests result from the need to facilitate maintenance, testing, repairs, and emergency restoration or safety concerns related to the Company's EPS.

### **1.5.2 Special Situations**

Under this bulletin, the Company restricts Generator-Owner or IC connection to the following situations.

#### **1.5.2.1 Net Generation Output**

The Company reserves the right to limit generation to its facilities operating to that level which will not compromise safety, reliability, or protection margins. Due to the many variable parameters involved, special requirements for any proposed net generation levels will be determined by the Company on a site specific basis. Export of surplus energy will require a power purchase agreement (PPA) between the Generator-Owner or IC and the Company in accordance with the applicable tariff provisions depending on whether such export is FERC jurisdictional or state jurisdictional.

#### **1.5.2.2 Peak Shaving Generation**

1. Arrangements for standby or supplemental energy needs are addressed by the Company's filed jurisdictional tariffs and shall be made prior to actual need to ensure its availability.
2. Peak shaving generation is customer-owned generator facilities operated in parallel with the Company's EPS to reduce a customer's electrical demand.
  - Peak shaving parallel generator installations, if not authorized under BTM Regional ISO programs, shall not be allowed to supply any net generation into the Company's EPS and will require the installation of protection devices (e.g., reverse power relays) to limit such power export onto the Company's EPS. The Company's revenue metering shall be detented in this case to prevent reverse billing meter registration. Where the Company is requested to supply demand pulse information (either analog or digital), its use is not intended for generator control.
  - Where PPAs, net energy metering (NEM), or BTM services apply, a peak shaving generator facility may be permitted to export into the Company's EPS under the requirements of this ESB 756 Appendix A.

## 2.0 PROJECT MANAGEMENT

### 2.1 Responsibilities

#### 2.1.1 Generator-Owner or IC

1. No generation, no matter its intent, shall be installed or operated in parallel with the Company's EPS without prior notification to and approval by the Company.
2. This responsibility applies to an initial generator facility, as well as to subsequent additions and/or modifications of Generator-Owner or IC equipment. Any subsequent sale of any generator facility covered by the requirements of the jurisdiction-applicable tariff will require the new owner to establish a separate interconnection agreement for the generation with the Company and comply with current parallel generation requirements. The Generator-Owner or IC is responsible for modifying their system to comply with any future mandate of the Company, Regional ISO, NERC(NPCC), and NERC or successor organizations including costs incurred.
3. If the Generator-Owner or IC makes significant changes in the design or scheduling of the generator facility, then any previous information furnished by the Company to the Generator-Owner or IC shall be subject to review and possible change. Failure to communicate such changes to the Company may result in delay of interconnection service or termination of interconnection service by the Company.
4. The Generator-Owner or IC is responsible for performing all operating functions associated with their equipment and for maintaining all equipment under their ownership. The Generator-Owner or IC shall arrange to have trained personnel available for the proper and safe operation of their equipment. The Generator-Owner or IC shall follow the Company's specified switching protocol upon commissioning, synchronizing, and return-to-service situations with the Company's transmission or distribution system operator; see ESB 755 for more information.
5. The Generator-Owner or IC shall provide proper and continuous maintenance of all plant facilities; refer to ESB 755 and National Fire Protection Association (NFPA) 70B (and NFPA 73 where applicable) and other nationally recognized industry standards for guidance on electric equipment maintenance.
6. The Company will specify telecommunication services as required for the installation. See Section 4.2 for data submittal to the local telephone company.
7. For the Company-owned RTU installation in NY, the Generator-Owner or IC shall arrange to provide the necessary telecommunication service as specified by the Company. As this process typically takes several months, the Generator-Owner or IC is responsible for submitting the information to their local telephone company, see Section 4.2, in a timely fashion. The Company will not be liable for the results of any delays.
8. The Generator-Owner's or IC's telephone number(s) shall allow for 24-hour per day contact of either a staffed control room or delegated operating agent.
9. If the Generator-Owner or IC is in part or whole selling energy or ancillary service directly to a wholesale generation market or aggregator, all dispatch signals shall be communicated to the Company's Control Center (day ahead up to and including real time). The communication of these dispatch signals shall be compatible with Company communication systems.
10. The Generator-Owner's or IC's backup service requirements from the Company's EPS shall be requested using the prescribed forms in the Company's jurisdictional tariffs.
11. Application Process:
  1. Parallel operation of a generator facility becomes a part of the Company's EPS whereby the Generator-Owner or IC and the Company have a mutual interest in ensuring that the interconnection meets the required electrical reliability and security of the Company's

EPS. This is necessary to ensure safety to the public and to Company employees and satisfactory operation, compatibility, and reliability with the electrical supply to other customers. The steps and timing requirements of the application process are identified within the jurisdiction-applicable regulatory requirements; see Scope section at the beginning of this document. The time required to complete the application process, however, may depend on the characteristics of the generator facility's system, the size class, its intended operating modes, and the characteristics of the Company's EPS at the point of interconnection (POI).

2. For new electric service or modifications to the electric service connection to accommodate the Generator-Owner's or IC's parallel generator facility, refer to the Company's latest revision of ESB No. 750, Specifications for Electrical Installations and its applicable supplements. The Generator-Owner or IC will be responsible for any permitting and conformance to the latest revision of all local, state and federal codes and national standards that apply. The Generator-Owner or IC will also be responsible for any additional costs associated with work completed by another entity (such as telephone company pole sets) and should be aware that project construction schedules can be significantly impacted by this other work.
3. When considering a new or modified generator facility interconnection arrangement, the jurisdiction-applicable tariff forms are required to be submitted to the Company.
4. The application process and attendant services are offered by the Company on a non-discriminatory basis to any Generator-Owner or IC and as a part, the Company may identify the need for detailed engineering studies, EPS upgrades, and additional protection requirements. As allowed by the jurisdiction-applicable electricity tariff, the costs of the detailed study and upgrades are the responsibility of the Generator-Owner or IC. If the Generator-Owner or IC makes significant changes in the design or installation scheduling of their generator and interconnection facilities, then any previous information furnished by the Company to the Generator-Owner or IC is subject to review and possible change, which may cause a delay in service.
5. Notice to the Company to install parallel generation shall be an application form from the jurisdiction-applicable electricity tariff, signed by the Company and the Generator-Owner or IC. This form shall include:
  - 1) Complete generator data sheets,
  - 2) The generation's intended purpose (*i.e.*, peak shaving or sale),
  - 3) Geographic location,
  - 4) Service point location (*i.e.*, circuit name and number, pole number, etc.),
  - 5) Contact information, name and telephone number of individual to be contacted regarding generator operation, and
  - 6) A provision stating that it is the responsibility of the Generator-Owner or IC to notify the Company, in writing, to obtain and complete a new application form whenever information changes.
6. A Letter of Commitment shall accompany the completed application form and including:
  - 1) Result(s) of the Company's electric study,
  - 2) Written authorization from the Generator-Owner or IC for the Company to proceed with engineering and construction of the interconnection including initial payment.

## 12. Contributions

1. All costs incurred by the Company as a result of a Generator-Owner's or IC's facility, over the life of that facility, shall be reimbursed to the Company by the Generator-Owner or IC. The Company will advise the Generator-Owner or IC concerning any charges and payment schedules required.

2. All costs incurred by the Company for supply system changes, metering upgrades, and telemetering circuit changes associated with the Generator-Owner's or IC's installation shall be reimbursed to the Company by the Generator-Owner or IC. These costs also include initial engineering evaluations, purchase and installation of additional switching, transmission and distribution equipment at Company's facilities, additional safety provisions, engineering, and administration. The Company will notify the Generator-Owner or IC when these situations arise along with their associated charges and execute terms and conditions for payment. These costs shall be paid in full by the Generator-Owner or IC prior to commencement of service in accordance with the jurisdiction-applicable electricity tariff.

### **2.1.2 Required Interconnection Study for Projects less than 115kV**

This study identifies the items of major cost to the interconnection. The scope of work is dependent upon the size and electrical location of the project. The study's primary function is to assess the impact the proposed project has upon the operation of the existing EPS and addresses the following principle areas:

#### **2.1.2.1 Thermal margins**

An assessment is made to ensure that the proposed project will not overload lines or impose operational constraints on the existing system.

#### **2.1.2.2 Voltage performance**

An assessment is made to ensure the proposed project can operate within voltage guidelines. For voltages less than 115kV, the guidelines are +5/-10% of nominal.

#### **2.1.2.3 Stability**

An assessment is made to ensure that local clearing times are such that unit stability is maintained and regional stability is not negatively impacted. Power system stabilizers shall be installed when such controls are required to dampen system oscillations.

#### **2.1.2.4 Short Circuit Studies**

A study is performed to ensure that circuit breaker duties remain within nameplate ratings with the addition of the project.

#### **2.1.2.5 Protection**

In this study phase an initial assessment is made to define required changes to local protection.

#### **2.1.2.6 Risk of Islanding**

Where required, a study is made to determine if the generator facility may island the local EPS under certain minimum load to generation match conditions and to define required changes to local EPS protection.

#### **2.1.2.7 REGIONAL ISO/NPCC/NERC**

Compliance with the planning standards of Regional ISO/NPCC/NERC will be required for Regional ISO-controlled interconnections.

### **2.1.3 Required Interconnection Study for Projects 115kV and Above in NY or 69kV and Above in New England**

For 115kV in NY or 69kV in New England and above connections, the Generator-Owner or IC shall contact and obtain from the Regional ISO the requirements for an approved interconnection study. In this study phase an assessment will be made to ensure generation connected to the state jurisdictional secured transmission system complies with Regional ISO/NPCC/NERC or successor organization's planning standards in force at the time of energization of the Generator-Owner's or IC's facilities. Note that this could apply at lower system voltage levels if the Generator-Owner or IC is selling power into the generation market.

#### **2.1.4 No Agreement for Power Sales**

Generator-Owners or ICs who generate in parallel for the purpose of reducing their energy and demand utilization from the Company EPS (*i.e.*, peak shaving generation) are not required to have a power purchase agreement with the Company. However, they still shall comply with the requirements of this ESB Appendix A and the Company's jurisdiction-applicable electricity tariff, as determined by the Company. The Company on a case-by-case basis shall determine additional protective devices. The Generator-Owner or IC is required to complete all Company jurisdiction-applicable tariff forms relating to generators. The Company will advise the Generator-Owner or IC of any change of service class.

#### **2.1.5 Purchase of Generator-Owner's or IC's Power**

1. Company's Retail Tariff Service Option: The Company will advise the Generator-Owner or IC concerning a retail Service Class contract (*e.g.*, PPA) for any power purchased from the Generator-Owner or IC by the Company in accordance with the Company's jurisdiction-applicable filed electricity tariffs.
2. Wholesale Option - Direct Sale to the Regional ISO: The Generator-Owner or IC shall enter into an agreement with a Regional ISO for the sale of energy. This arrangement requires a separate agreement with the Company for the interconnection of the generating facility. Where the Generator-Owner's or IC's facility is a DER, they may commit the output to a third party DER aggregator in order to sell in the Regional ISO generation market (*i.e.*, direct sale or transacting with a third party engaged in sales to the Regional ISO). Under the aggregation model, the Generator-Owner or IC or DER Aggregator shall consult the Regional ISO for the applicable interconnection rules as well as FERC for any required filings.

#### **2.1.6 Interconnection Agreement**

1. A signed Interconnection Agreement along with any other completed generator-related jurisdictional tariff form(s) is required between a Generator-Owner or IC and the Company, and, if necessary, the Regional ISO. For generator facilities connected to distribution systems under Company jurisdiction-applicable electricity retail tariffs, see ESB 756 Appendices B, C, and D.
2. In general, the Interconnection Agreement will address the mutual acceptance of an interconnection study, which outlines any required electric system modifications and overall project capabilities, specifically:
  - 1) The amount of the generation, by unit and/or in total,
  - 2) The interconnection point voltage,
  - 3) The generator facility's intended purpose (*i.e.*, peak shaving or sale),
  - 4) Its geographic and electrical location, including feeder location where applicable.
  - 5) Electrical arrangement and protection requirements,
  - 6) Electric study results of project generation impact,
  - 7) Estimated cost, funding schedule, and timeline required to implement any needed modifications to the Company's EPS to accept generation from the Generator-Owner or IC,
  - 8) Reimbursement to the Company for the operation and maintenance to be performed by the Company on the interconnection facility,
  - 9) Additional agreements deemed necessary for project acceptance,
  - 10) Contact information, name and telephone number of individual to be contacted regarding generator facility's operation, and
  - 11) Responsibility of the Generator-Owner or IC to notify the Company in writing whenever any change in the above information is contemplated, changes are subject to the approval of the Company.

3. A signed Interconnection Agreement is required between the Generator-Owner or IC and the Company before the Company will order major equipment or proceed with interconnecting the generator facility.

## 2.2 Cooperation

### 2.2.1 Overall Project

1. Any generator facility intending to operate with an interconnection to the Company's EPS shall have the approval of the Company. Generator connections for the purpose of selling to the system require approval of the appropriate Regional Independent System Operator. This approval shall be in the form of a signed Interconnection Agreement. An Interconnection Agreement will not only identify changes to the existing EPS, but will specify Generator-Owner or IC plant performance requirements that may impact the specification major electrical components within the generator facility itself.
2. If the Generator-Owner or IC enters into an agreement with a DER Aggregator, the Company will require a separate agreement with the DER Aggregator to ensure the aggregated generator facilities' operation are within the Company's requirements.
3. The Company will own, operate and maintain all electric lines and stations to the service point or POI where applicable. There will be many occasions where the close cooperation between the Company and the Generator-Owner or IC during the design, license, right-of-way acquisition, and/or construction of Company facilities will be necessary. See the Company's **ESB 751** "General Requirements Above 600-volt Service" for more information.

### 2.2.2 Notification and Initial Documentation

1. The Generator-Owner or IC shall contact the Company regarding their desire to operate generation in parallel with the Company EPS and negotiate necessary agreement(s). In some cases, the Company will meet with the Generator-Owner or IC to mutually establish the arrangement and location of the proposed facilities.
2. Upon notification by a Generator-Owner or IC of their intention to operate generation in parallel with the Company EPS, in writing, the Generator-Owner or IC shall define their vision of the proposed project; providing the proposed site location, overall plant capabilities, the number, and size of equipment proposed, and proposed timing of project milestones. The Generator-Owner or IC shall develop and provide a functional single-line diagram, complete with voltage and current interrupting ratings, type of equipment proposed, and all controls, complete with trip schemes, required by system protection parameters for proper protection and coordination with the EPS for Company acceptance. In addition, the specific project documentation indicated in this bulletin is also required. Three copies of each document, stamped by a State-registered professional engineer, are required unless noted otherwise.
3. Subsequent to this notification, the Company will review the project proposal and provide to the Generator-Owner or IC the estimated cost and time table for delivering the results of an electric study. The Company will respond with review comments on the concepts of the service arrangement, protective relaying, metering, and any special requirements that may be needed for an electric study (see Sections 4 and 5 herein). Data requirements for an interconnection study of generator facility projects are:

#### 2.2.2.1 Study Phase:

Three copies of the following are necessary to begin the Company's study:

- (1) Exact physical location of the plant identified on USGS maps.

A site plan shall be submitted that is stamped and signed by a professional engineer licensed in the state where the project will be installed. The site plan shall show 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 Generator-Owner or IC shall submit a scaled site plan with location of below equipment:

- Interfacing transformer(s).
- Interrupting device(s).
- PCC.
- Mainline extension to site and from nearest PCC.
- Existing and proposed access road including, at a minimum, road material, surface loading criteria, and dimensions to confirm Company personnel and equipment access requirements are met.
- Generator location.
- Certified Scaled Site Plan and Assessor Survey Map with Wetlands.

Note that site plans shall be to scale with approximate distances indicated. In addition to site plan, the Company may ask for an assessor survey map to determine property lines, wetlands, and easements.

- (2) Overall operational output (in MW) of the generator facility.
- (3) Proposed single-line diagram of the generator facility's station showing the interconnection of major electrical components within the plant itself. This single-line diagram indicating proposed equipment ratings clearly needs to indicate:
  - (i) Number, individual ratings & type of units comprising the above rating,
  - (ii) Number and size of GSU transformers, and
  - (iii) General high voltage bus configuration and relay functions.
- (4) The Company reserves the right to request additional information as needed specific to the interconnection of the generator facility's equipment including, but not limited to, three-line diagrams, control diagrams, equipment test reports and other information; see the Company's ESB 751.

Control Diagrams for < 600V Generator Facility: The Generator-Owner or IC shall submit all control diagrams (i.e., DC control schematics) of the equipment associated with the interconnection protective system. Control diagrams depict all logic used to control the interconnection protective devices. If programmable logic controllers are used for these functions, a copy of the ladder logic and reference table(s) must be included.

- (5) General operational constraints such as the ability to run various combinations of units.
- (6) The following is a list of Electrical Data Requirements:
  - (i) Proposed GSU transformer MVA ratings, impedances, tap settings and winding voltage ratings.
  - (ii) Proposed machine or inverter electrical parameters noted on technical data sheets which include:
  - (iii) Machine nameplate data and reactive capability curves.
  - (iv) Impedances:
    - Direct axis and quadrature axis synchronous reactance;
    - Transient and subtransient components of positive sequence reactance data;
    - Negative sequence and zero sequence values.
  - (v) Time constants for both field open circuit and short circuit and armature short circuit quantities.
  - (vi) Turbine inertia constant.

- (vii) Generator inertia constant: Appropriate IEEE system model including block diagram and parameter values for excitation and governor systems.
  - (viii) Inverter type and characteristics with manufacturer name and model number.
- (7) The proposed location and arrangement of Company metering equipment will be furnished by the Company and shall be included on the Generator-Owner's or IC's drawings when submitted for acceptance.

#### **2.2.2.2 Equipment Procurement Phase:**

Either before an order is placed for electrical equipment or while in equipment manufacture scheduling prior to delivery, six (6) copies of equipment specifications, Protective Relay Device List, and a Bill of Material List shall be furnished to the Company for review and acceptance. Review and acceptance by the Company shall not be construed to be an approval of the Generator-Owner's or IC's installation in regard to its overall safety or adequacy, but shall simply signify that the proposed arrangement and equipment meets the Company's interconnection requirements for connection to the Company's EPS.

#### **2.2.2.3 Final Design Start Phase:**

The documents needed to be submitted to the Company prior to beginning the final design shall include a proposed time schedule to be mutually agreed upon, a plot plan and functional single line diagram showing protection, a protective relaying scheme and revenue metering. The relay types selected to provide these functions must be acceptable to the Company. The Company will respond with the review comments on the concepts of protective relaying, metering and telemetry. This single-line diagram must be approved before final design is undertaken.

### **2.3 Development of an Interconnection Arrangement**

#### **2.3.1 Initial**

Parallel generation will be accepted on the Company EPS at various voltage levels depending upon the generation installed and the capability of the circuit(s) to accept the electric power generated. The system will be studied in each case.

##### **2.3.1.1 Funding:**

Generator-Owners or ICs are required to establish an account with the Company. This account shall hold sufficient funds to cover the Company's estimated cost of the development of an interconnection arrangement and, upon its acceptance, scheduled payments for project installation in accordance with jurisdictional tariffs. Once sufficient funds and required data have been received, the Company will start work on the interconnection arrangement as directed by the Regional ISO.

##### **2.3.1.2 Presentation:**

A meeting will be scheduled with the Generator-Owner or IC to formally convey, explain, and answer questions regarding its content. This meeting also provides an opportunity to update information, if necessary, for the installation phase of the project.

##### **2.3.1.3 Acceptance:**

The Generator-Owner or IC shall signify acceptance of the interconnection arrangement by providing a signed Interconnection Agreement and any necessary completed generator-related Company jurisdiction-applicable tariff forms and payment of any scheduled funding. The Company will not proceed with any work until these items are received.

#### **2.3.2 Project Scheduling**

Upon acceptance of the interconnection arrangement, the Generator-Owner or IC shall submit their project schedule. This schedule and subsequent changes will be mutually agreed upon.

### **2.3.3 Generation Scheduling**

1. Generator-Owners or ICs selling into a Regional ISO generation market will submit bids as required by that ISO. Testing and outages will also be scheduled per the Regional ISO requirements.
  - 1) In addition, for generation 10,000kVA and larger:
    - (1) To report the expected duration of a forced outage within 48 hours.
    - (2) To report non-scheduled maintenance or forced outages upon occurrence.
    - (3) To report 3-year planned maintenance outage requirements (expected duration, desired date and time) quarterly or as changed. The Generator-Owner or IC shall agree to an overall coordinated schedule to be provided by the Company.
  - 2) The Company, at its discretion, may extend the above requirements to installations of smaller size than indicated.
2. The Generator-Owner or IC shall be required to supply reactive power support when directed by the Company's transmission system operator or Regional ISO up to the agreed specified limit.
3. All generator facilities interconnected to the distribution system and participating in the wholesale generation markets hourly or real-time dispatch, will require communication of day-ahead up to real-time dispatch signals to the Company.
4. The Company is currently providing, and will continue to provide, reactive power (*i.e.*, VAR) support to the distribution EPS. In the future, as technology and market evolution occurs, DER may also provide VAR support on a dynamic basis as requested by the Company. For advanced technologies that can provide VAR support, such as smart inverters, the Company will require manufacturer information specific to the technology to fully understand its functionality and ascertain monitoring and control requirements prior to the technology's application for VAR support.

## **2.4 Compliance**

The Company's rights to confirm and verify the compliance of the generator installation are described in ESB 750 or 752 as applicable, ESB 751, and ESB 755. This includes energization and synchronization prerequisites, periodic checks and tests, and as-built documentation. In addition, an executed interconnection agreement shall be submitted four weeks in advance of energization.

## **3.0 SERVICE INSTALLATION**

### **3.1 Service Equipment**

The Generator-Owner or IC shall provide service entrance equipment as a part of their installation. The Generator-Owner's or IC'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.

### **3.2 Grounding**

As a minimum, the Generator-Owner's or IC's generator facility equipment shall be grounded in accordance with the latest requirements of the NEC or the NESC where the Generator-Owner or IC is under state utility regulation status. For specific installations, refer to the applicable sections of this document and the Company's ESB 750 and its applicable supplements. For neutral stabilization and ground fault requirements on distribution systems, see ESB 756 Appendices B, C, and D.

### **3.3 Metering**

The Company reserves the right to determine that all metering schemes allow for the proper administration of all contracts and rates (whether retail or wholesale). Additional Company

metering requirements are specified in the appropriate sections of this ESB 756 Appendix A and the Company's various jurisdiction-applicable electricity tariffs, as filed and Regional ISO requirements, as applicable within the process.

### **3.3.1 Metering Requirements in MA, NH, RI, and VT Jurisdictions**

1. For Distribution Metering requirements under the Company's jurisdiction-applicable retail electricity tariffs in MA and RI, refer to the Company's ESB 750 and ESB 756 Appendices C and D at <http://www.nationalgridus.com/electricalspecifications>.
2. For Transmission Interconnectors' metering and communication requirements in MA, NH, RI, and VT, refer to ISO-NE OP-18 and all appendices at [https://www.iso-ne.com/static-assets/documents/rules\\_proceeds/operating/isone/op18/op18\\_rto\\_final.pdf](https://www.iso-ne.com/static-assets/documents/rules_proceeds/operating/isone/op18/op18_rto_final.pdf).

### **3.3.2 Metering Requirements in Upstate NY Jurisdiction**

1. For Distribution Metering requirements under the Company's jurisdiction-applicable retail electricity tariff in NY, refer to the Company's ESB 750 and ESB 756 Appendix B at <http://www.nationalgridus.com/electricalspecifications>.
2. For Transmission Interconnectors' metering and communication requirements in NY, refer to NYISO "Revenue Metering Requirements Manual", No. 25 at [http://www.nyiso.com/public/webdocs/markets\\_operations/documents/Manuals\\_and\\_Guides/Manuals/Administrative/rev\\_mtr\\_req\\_mnl.pdf](http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Administrative/rev_mtr_req_mnl.pdf).

### **3.3.3 General Parallel Generation Requirements for Company Metering**

1. Details of the installation requirements are covered in ESB 750 and its appropriate Supplement. For generator facilities connected to distribution systems, see also ESB 756 Appendices B, C, and D.
2. Where energy will be sold to the Company, a directional revenue metering system will be installed.
3. Normally, for installations with directional revenue metering the connection of the Company's metering instrument transformers must have a potential transformer (PT) connected on the generator side of the current transformer (CT). The instantaneous relative polarity of metering instrument transformers is critical to proper operation. CTs must be positioned such that the polarity dot or marking is on the Company side.
4. Revenue meters will either be equipped with detent functionality, or will be capable of bi-directional measurement. "Detented metering" measures and registers power flow in a single direction by either mechanical or electronic means.
5. A directional revenue metering system will be installed to capture bi-directional kilowatt-hours (kWH). Depending on magnitude of load/generation, kilowatt demand (kW) and kilovar-hour (kVARH) quantities will also be captured. For those installations having a "Buy All-Sell All" purchase agreement contract, an additional interval based kWH meter will also be installed on the output of the generator(s).
6. Where NEM does not apply or for peak shaving generator applications excluded from BTM or excess sales arrangements, there is no obligation for the Company to accept surplus power and in those cases, the Company's revenue metering will be detented.
7. In NY at the Generator-Owner's or IC's request and cost, the Company will furnish equipment for energy pulse signals. These signals will be at the point of the metering and will represent the kWH energy for operation of their equipment. These signals are for information only and the Company shall not be liable for distorted or missing pulses.
8. Where applicable under the Company's jurisdiction-applicable tariff, Non-Residential Customers with OSG are subject to billing adjustments, for example primary served/secondary metered customers. Additional metering will be installed at the Generator-Owner's or IC's expense in order to measure the appropriate adjustment.

9. The Company will make the final determination of telecommunications service requirements for Company-owned revenue metering.
10. The Generator-Owner or IC is responsible for arranging for installation and payment of all costs associated with the telecommunication service to each Company-owned revenue meter board; see Section 4.2. They are also responsible for all maintenance costs and recurring telecommunication charges.

## **4.0 PLANT REQUIREMENTS**

### **4.1 Telemetry**

#### **4.1.1 Telemetry Criteria**

1. The Company reserves the right to determine all telemetry and supervisory control data acquisition (SCADA) schemes to allow reliable operation of the electric system and for the proper administration of all contracts.
2. For all installations 1,000 kW or larger, telemetry of data, control and/or status of devices as specified by the Company is required. The Company also reserves the right to extend the need for telemetry to less than 1,000 kW generators or where Merchant Plants desire this equipment for their Regional ISO requirements. This information is for the Company's Energy Management System (EMS) and will require the installation of Remote Terminal Unit (RTU) equipment in the Generator-Owner's or IC's facilities. *Exception: Where the Company supplies a PCC recloser, SCADA provisions may be sufficient for the EMS reporting requirements and a generator facility EMS-RTU is not required for status and control.*
3. Subject to the jurisdictional applicable tariff, the Company or the Generator-Owner or IC will furnish the telemetry RTU for the installation. The Company will specify the communication protocol, polling frequency, transducers, sensors or other components that the Generator-Owner or IC will purchase and acquire. Where equipment is furnished by the Company under the Company's jurisdiction-applicable tariff, it will remain Company property and will be maintained by the Company.
4. All dispatch signals whether from the Regional ISO or DER aggregator will be transmitted to the Company utilizing Company-specified communication system protocols.

#### **4.1.2 Telemetry Specifications for Company-provided RTU**

1. The RTU cabinet is typically 42" H x 30" W x 26" D shall be wall-mounted with the bottom edge 36" above the floor. A 5-foot clear working space shall be maintained in front of the mounting panel.
2. A dedicated 20A, 120VAC, single phase 60 hertz power circuit is required for the RTU cabinet. All conduit and wiring (minimum of No. 10 AWG copper) to the telemetry cabinet for this circuit shall enter the cabinet from the bottom. A three (3) foot length of all conductors shall be provided for final Company connection.
3. A dedicated 10A, 48VDC or 125VDC input is required to the RTU directly from the station battery.
4. The Generator-Owner or IC will be responsible for mounting this equipment in their installation, subject to Company approval. The Generator-Owner or IC will provide space, power and all input connections for this package, in the same area with the metering equipment (see ESB No. 752).
5. The following guidelines shall be adhered to:
  - 1) The RTU shall be located indoors within 15 feet of the billing meters to facilitate testing and calibration.
  - 2) The RTU shall be remote from heavy traffic areas, work areas and loading areas.

- 3) The RTU shall be remote from heat producing or high electrostatic or electromagnetic field producing equipment.
- 4) The RTU shall be remote from station batteries.
- 5) The analog inputs to the RTU shall be +1.0mA DC at rated input, +2ma DC maximum. The analog metered inputs required as metered at delivery point are as follows:
  - Net kW (+) - To the Company EPS
  - Net kW (-) - From the Company EPS
  - Net kVAR (+) - To the Company EPS
  - Net kVAR (-) - From the Company EPS
6. Where the Generator-Owner's or IC's system includes generation and plant load, the metered values shall be the net sum of power from the Company's EPS, and the generation minus any internal plant load, which may be connected to the generator output circuits.
7. The Accumulator inputs to the RTU shall be:
  - Net kWh (+) - To the Company EPS
  - Net kWh (-) - From the Company EPS
8. The bi-directional metering equipment for telemetering shall be capable of providing instantaneous power and a pulse output that is proportional to integrated energy.
9. Additional inputs that normally will be required are:
  - Phase Voltage (kV) and Current (Amps) - measured at the interconnection bus (service voltage)
  - Circuit breaker(s) control and/or status
  - Motor operated disconnect(s) status
  - Instantaneous value of frequency (Hz) - if so specified
  - Ring bus station voltage, current, active and reactive power at several locations.

*Note: The Company will provide an EMS-RTU point list for inputs required at the Generator-Owner's or IC's facility.*

#### **4.1.3 Telephone Installation Specifications for Company-provided RTU**

1. A plywood panel 3/4" x 48" x 48" is required for the telephone equipment. A four (4) foot clear working space shall be maintained in front of this panel. The Generator-Owner or IC will install terminal blocks directly adjacent to the telephone equipment for interconnection of the Company's EMS-RTU.
2. A dedicated 20A, 120VAC, 60 hertz power circuit is required for the telephone equipment. The Generator-Owner or IC shall provide all conduit and wiring for the circuit and install one 20A, 120VAC, single phase convenience receptacle at the telephone equipment location.
3. Refer to Section 4.2 herein for telecommunication provider steps and requirements.

## **4.2 Telecommunications Steps and Requirements**

1. The local serving telephone company's facilities demarcation and equipment shall be located as close to the RTU cabinet and protection relays, as feasible, relative to the Generator-Owner's or IC's mutually agreed upon location.
2. The Generator-Owner or IC is responsible for arranging the installation and paying all costs associated with required telecommunication line(s) for all RTU and tele-protection circuits (e.g., DTT) including maintenance and recurring telephone company charges as documented in the interconnection study or interconnection agreement .
3. The Generator-Owner or IC shall be responsible for all telephone company coordination, installation, final connections, and commissioning of all required telecommunication circuits.

4. The Generator-Owner or IC is responsible to complete their telephone company's high voltage protection (HVP) form when arranging for the telecommunication service. The technical information normally provided includes, but not limited to: total square footage area of Ground Grid/Mat, Grid Impedance (in Ohms) to Remote Earth, total expected Fault Current (line-to-ground) in Amps RMS (or Amps Peak), Earth Return Current (as % of Total Fault Current), X/R Ratio, and Soil Resistivity (layer depth information in feet).
5. The Generator-Owner or IC is responsible to comply and coordinate with their telephone company's commissioning process of telecommunications circuits required with the Company.

### **4.3 Power Quality**

Utility lines are subject to many natural and man-made hazards. The Company does not assume any responsibility for protection of generation or other electrical equipment. The Generator-Owner or IC is fully responsible for protecting all of their equipment from damage due to faults and other disturbances, irrespective of the condition of the Company's EPS. The Generator-Owner or IC shall not impact the Company's EPS power quality characteristics.

### **4.4 Performance/Design**

#### **4.4.1 Generator Criteria**

1. The Generator-Owner or IC shall provide generator controls to maintain proper voltage, frequency, and line current balance and permit synchronizing with the Company EPS. The generator facility's electrical output shall meet the performance requirements of the latest IEEE Standard 519 and ANSI C84.1 at the time it goes into service.
2. All generation projects operating in parallel with the Company's EPS shall not adversely impact the existing system operation. Transmission lines shall remain within thermal ratings for normal and contingency conditions and the proposed project shall be capable of operation at full output over the range of system operating voltages. This range includes the normal nominal voltage range of 1.05p.u. to 0.95p.u. and the emergency range, which can extend to 0.90p.u. for short periods of time.
3. Projects utilizing synchronous and doubly-fed asynchronous machines are required to have excitation systems capable of automatic terminal voltage control. In general, long term operation with constant excitation (manual mode) is not acceptable. If power factor control is available it must be automatically disabled following a system disturbance to ensure sustained reactive support after an event. Power factor control and automatic voltage control schemes shall be mutually agreed between the Generator-Owner or IC and the Company. These requirements may typically lead to operational power factors at the Wholesale Delivery Point ranging between 0.9 lagging (VARs to the power system) and 0.95 leading (VARs from the power system). (Retail electric load customers with on-site generation shall provide reactive power support such that the retail load power factor is not degraded at the Retail Delivery Point.)
4. Projects utilizing induction machines will be required to utilize switched shunt compensation within their facility to minimize system voltage impacts over a wide range of the entire power output. Local power system requirements may lead to operational power factors at the Wholesale Delivery Point or Retail Delivery Point ranging between 0.9 lagging (VARs to the power system) and unity. These facilities will also be required to meet the latest Regional ISO, NPCC, or local regional planning criteria. The overall project power factor requirements shall be mutually agreed between the Generator-Owner or IC and the Company.
5. Voltage and Frequency Control:  
Plant equipment is required to remain on line and fully operational throughout this recovery period. Voltage and frequency ride through and trip points for generation connected to the

Company's EPS shall meet two standards, IEEE 1547 and NERC PRC-024-2 depending on the size and type of the generator facility.

- 1) Inverter-based generators, 10MVA and less, shall be in compliance with the latest version of IEEE 1547 and its amendments. The current amendment to the standard, IEEE 1547a, requires voltage and frequency ride through capabilities be available in all inverter based generation. The Generator-Owner or IC shall provide the voltage and frequency ride through capabilities specified by IEEE 1547a in any inverters installed as part of a generator facility proposed to interconnect to the Company's EPS and shall refer to ESB 756 Appendices B, C, and D where connected to distribution systems less than 15kV.
- 2) Generator plants including small distributed generators shall conform to the current version of IEEE 1547 for their voltage and frequency settings, including generators rated greater than 10MVA.
  - No distributed generators shall have an under-frequency trip setting higher than 58.9 Hz, as to not conflict with the under-frequency load shedding schemes in the Company's EPS.
  - For the "adjustable" under frequency setting in table 2 of IEEE 1547, setting shall not fall within the prohibited region of NERC PRC-024-2.
- 3) Generator facilities that have aggregate generation greater than 20MVA and connected through a GSU transformer to a transmission line that is greater or equal to 100kV shall conform to the current NERC PRC standards including NERC PRC-024-2. These generators are considered part of the "Bulk Electric System" ("BES").
  - Power plant auxiliary equipment shall not trip or stall for momentary under voltage or over voltage excursions anticipated by planning criteria.

Note that in IEEE 1547, the pickups are exact set points and the time delays are maximum total clear (including relay and breaker op time). In PRC-024-2, the pickups and time delays are the algorithm for a "prohibited region." The Generator-Owner's or IC's settings do not need to be exactly on the lines for this prohibited region, they just cannot be within the region that the lines envelop. IEEE 1547 focuses toward maintaining power quality and safety, since a majority of the systems it applies to are on the distribution EPS, close to customer loads and more susceptible to faults. The PRC rules focuses on maintaining the reliability of the BES, and preventing system collapses. For more information, see:

- IEEE 1547: [http://www.techstreet.com/standards/ieee/1547\\_2003?product\\_id=1094603](http://www.techstreet.com/standards/ieee/1547_2003?product_id=1094603) and [http://grouper.ieee.org/groups/scc21/1547a/1547a\\_index.html](http://grouper.ieee.org/groups/scc21/1547a/1547a_index.html)
- NPCC reliability criteria: <https://www.npcc.org/Standards/Directories/Forms/Public%20List.aspx>
- NPCC Directory 12 Curve, Figure 1 for the adjustable underfrequency set point (Eastern interconnection): <https://www.npcc.org/Standards/Directories/Directory12%20Full%20Member%20clean%2020150330%20GJD.pdf>
- PRC-024-2 (Eastern interconnection): [http://www.nerc.com/\\_layouts/PrintStandard.aspx?standardnumber=PRC-024-2&title=Generator%20Frequency%20and%20Voltage%20Protective%20Relay%20Settings&jurisdiction=United%20States](http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-024-2&title=Generator%20Frequency%20and%20Voltage%20Protective%20Relay%20Settings&jurisdiction=United%20States)

#### **4.4.2 Step-up Transformer Specification**

1. GSU transformer connections and winding configurations shall be reviewed and approved by the Company before procurement by the Generator-Owner or IC. Acceptable equipment parameters are often determined by the location on the electrical system. The winding arrangement shall be such that the Company's EPS remains effectively grounded. For generator facilities connected to distribution systems, see ESB 756 Appendices B, C, and D.

2. GSU transformer and auxiliary transformers shall have no-load tap settings and impedances coordinated with power system voltage control requirements and unit capabilities.

## **4.5 Plant Protection**

### **4.5.1 Plant Protection Criteria**

1. Excitation equipment shall have an over excitation limiter coordinated with the thermal capability of the generator field winding. Longer over excitation time shall allow less overcurrent. The over excitation limiter shall also be coordinated with over excitation protection so that over excitation protection only operates for failure of the voltage regulator/limiter. Return to automatic voltage control after an over excitation event shall be automatic.
2. Under excitation limiters shall coordinate with generator capability (stator end-region heating) and power system stability limits. These settings shall also coordinate with loss of excitation protection.
3. Volts/hertz limiter equipment shall coordinate with volts/hertz protection.
4. Prime mover control (governors) shall operate freely to regulate frequency. Droop setting shall be in accordance with Regional ISO/NPCC/NERC standards. Prime movers operated with main valves or gates wide open shall control for over speed/over frequency. Boiler or nuclear reactor control and protection shall coordinate to meet the economic and safety requirements of the plant while maintaining the capability of the generator to aid in the control of system frequency during a power system disturbance.
5. Prime mover over speed controls shall be designed and adjusted to prevent boiler upsets and trips during partial load rejection characterized by abnormally high system frequency.
6. Recording of performance during disturbances shall include generator terminal voltage and real and reactive power. Monitoring of other quantities such as field voltage and current, power system stability (PSS) output frequency or speed is best practice. These event recorders shall have adequate resolution and bandwidth to fully capture dynamic response of the generator.
7. Protection shall allow temporary excursions in speed and system frequency anticipated by planning models without tripping. Such protection shall include over/under frequency relays as well as boiler safeguards. Under frequency protection shall be coordinated with the Regional ISO/NPCC/NERC under frequency load shedding program.
8. Generator protection shall allow temporary voltage excursions anticipated by planning models without tripping. This protection shall include volts per hertz relays, generator auxiliary equipment under voltage relays, loss of excitation relays, backup distance relays, generator and transformer overcurrent relays, and out-of-step relays. These protection characteristics and settings shall be available to the Company upon request.
9. For parallel generation interconnected greater than 15kV, frequency protection employed on all rotating apparatus shall allow the system time to recover by keeping units on-line during short term frequency excursions. With reference to NERC PRC-024-2 above, a region is indicated during which the system frequency is recovering. Generation shall remain on line during this period. The lower bound is established by Regional ISO/NPCC/NERC criteria. The upper bound is for uniformity among projects taking into consideration equipment capabilities and the characteristics of the system response. All generation shall be capable of operating within this region.

### **4.5.2 Automatic Switching and Protective Devices**

1. The generator facility shall employ the use of a properly applied interrupting device capable of automatic operation to interrupt the generation facility from the Company's EPS. The device to be used shall be reviewed and approved by the Company before procurement by the Generator-Owner or IC. The Generator-Owner or IC shall provide protection as determined by the Company on a site-specific basis.

2. The Company shall review and approve the protective relay devices provided by the Generator-Owner or IC for protection schemes required by the Company to protect its system. The use of utility grade relays and relay redundancy is a normal Company requirement. See Exhibit 1 for a reference list of most device nomenclature.
3. For interconnections on the Company's transmission system, frequency relays, where used, shall have ranges to meet the requirements of the Plant Abnormal Frequency Requirements Curve, see NERC PRC-024-2 referenced above. Voltage relays, where used, shall have ranges to meet the Company's transmission planning criteria of  $\pm 5\%$  from nominal voltage and  $-10\%$  for emergencies.
4. Protective relay devices provided by the Generator-Owner or IC for Company-required protection schemes shall meet Company test device requirements.
5. **Exclusion of Current Transformer Selector Switches:** Meter selector switches shall not be connected into the secondary circuits of current transformers used with protective relays specified by the Company. Metering shall not be connected in protective relay circuits.
6. It is Company practice to automatically reclose line circuit breakers, without employing synchronism check protection, within a few seconds after they have automatically been opened. For specific distribution EPS reclosing, see ESB 756 Appendices B, C, and D.
7. **Anti-islanding:** Following a DER generator disconnection as a result of Company distribution source loss, the generation shall remain disconnected until such time as the Company source has recovered to Company acceptable voltage and frequency limits for a minimum of five (5) minutes. For merchant power plants, reconnection to the Company's transmission source shall be made through mutually agreed operating procedures and switching protocol with the Company's Transmission Control Center. There are severe safety and potential equipment damage issues associated with feeding power into a de-energized EPS. Any Generator-Owner's or IC's installation's protection system shall be designed with interlocks and proper protective functions to ensure that there is proper voltage, frequency and phase angle conditions between the Company's EPS before the generator facility is permitted to parallel. Therefore, anti-islanding protection control is required for parallel generation on the Company's EPS. If the Company determines that an active anti-islanding protection scheme is required to mitigate the risk of a formation of an island in addition to the generator facility's own anti-islanding control scheme then the Generator-Owner or IC may propose alternative methods of anti-islanding protection of their own generation facility that can see and trip for faults on the utility EPS and any upstream device opening. It is the Generator-Owner's or IC'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. The use of DTT is a definitive protection means for anti-islanding protection under good utility practice.  
*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 National Grid ESB 750, Section 11.*
8. For specific technical requirements of parallel generation up to 10MVA interconnected under **15kV** to the **Company EPS**, see ESB 756 Appendices B, C, and D.

<b>EXHIBIT 1: REFERENCE LIST OF STANDARD DEVICE NUMBERS</b>	
(See latest edition of ANSI C 37.2)	
<u>Device Number</u>	<u>Function</u>
25	Synchronizing Device
27	Undervoltage Relay
32	Directional Power Relay
46	Negative Sequence Voltage
50	Instantaneous Overcurrent Relay
51	Phase Overcurrent Relay
51C	Voltage Controlled Overcurrent Relay
51N	Neutral Overcurrent Relay
51V	Overcurrent Relay, voltage restraint
52	Breaker
52R	Recloser
59	Overvoltage Relay
59G	Neutral Voltage Relay
59N	Zero Sequence Voltage Relay
62	Time-delay Stopping or Opening Relay
64	Ground Protective Relay
81	Over and Under Frequency Relay
86	Locking - Out Relay
87	Differential Relay

(Refer to latest editions of NFPA 70B or IEEE Standard 141 for typical electrical single-line diagram development.)

#### **4.5.3 Relay Settings and Testing**

1. Protection shall be provided by the Generator-Owner or IC such that abnormal conditions on the Company's EPS will not cause damage to generator facility equipment. Protection also shall be provided by the Generator-Owner or IC such that abnormal conditions in the generator facility equipment will not cause equipment damage or abnormal conditions on the Company's system.
2. Company-designated Relays and Generator-Owner or IC Settings: The Company will review for acceptance the Generator-Owner's or IC's settings and the calibration and test results of those relays that the Company's Protection Engineering Department designates as being required to satisfy the Company's protection practices. In addition, the Company may require the relaying summary and logic diagrams depending on the complexity of the installation. Any relay setting issued by the Company shall not be changed or modified at any time without the prior written consent of the Company.
3. Company Verification of Relay Testing: Upon initial installation or modification, the Company requires a letter from the Generator-Owner or IC stipulating that all Company-designated protective devices shall have:
  - control wiring verified against the accepted design drawings, and
  - the calibration test performed satisfactorily according to the relay setting document of the accepted design.

The Company reserves the right to witness the Generator-Owner's or IC's functional test of the required devices, *i.e.*, trip tests. This activity will normally be performed on a mutually accepted schedule. At the Company's sole discretion, the calibration and test by a third party with Company approval of results may be an option. Refer to ESB 755 for additional details on the Company's policy regarding maintenance.

4. **Generator-Owner or IC Supplied Relay Settings and Testing:** The Generator-Owner or IC shall be responsible to specify the settings, calibrate, test, and maintain the balance of their equipment.
5. The NPCC has established criteria for periodically testing under frequency relays and reporting their performance used for load shedding critical to system security. Details of schedules, testing and reporting methods will be made available prior to synchronization.

## 5.0 OPERATING

### 5.1 Manual Disconnect Switch

The Generator-Owner or IC shall furnish and install an electrical load break disconnect switch accessible at all times to the Company. For disconnect switch requirements of generator facilities connected to distribution systems, see ESB 756 Appendices B, C, and D. This disconnect shall be connected between the Generator-Owner's or IC's facility and the connection point to the Company EPS. The visible disconnecting means may consist of a group-operated load air break switch and fuse, or group operated air break switch and circuit breaker. It shall be capable of being locked in the open position and have provisions for both Company and Generator-Owner or IC padlocks. This disconnect device shall be identified by a permanent sign as designated by the Company. Operation of this switch for any change in its status shall be immediately reported to the Company.

### 5.2 Disconnection by the Company (Isolation)

- 5.2.1 The Company reserves the right to open or order open the connection to the Generator-Owner or IC via circuit breaker, switches, etc., to isolate the Generator-Owner's or IC's equipment without prior notice for the following reasons:
  - 5.2.1.1 Emergency conditions on the transmission system that need to be relieved immediately requiring such action. Emergencies include but are not limited to:
    - Voltage excursions in excess of  $\pm 5\%$  of nominal.
    - Transmission system elements subjected to loading (pre- or post-contingency) in excess of thermal ratings where disconnection alleviates the problem.
    - Situations involving restoration of service.
    - Excess generation on the Company's EPS.

*Note: When reduced generation output alleviates the problem, it may be ordered by the Company.*
  - 5.2.1.2 When the Company's periodic check of Generator-Owner's or IC's equipment reveals a hazardous condition, a lack of necessary maintenance, or a lack of maintenance records for equipment necessary to protect the Company's EPS.
  - 5.2.1.3 When generating equipment interferes with other generator facilities, other customers, or with the operation of the Company's equipment. See Section 4.4.1 herein for Generation Criteria.
  - 5.2.1.4 When required protective relaying and/or tele-protection is altered, inoperable, or missing.
  - 5.2.1.5 When required special equipment necessary for operating control (e.g., telemetering/SCADA) on the Company's EPS is inoperable or missing.
- 5.2.2 Only the Company may permit the Generator-Owner or IC to energize a de-energized Company circuit for system restoration.

### 5.3 Other

1. In some instances, it may be required for Company operation of circuit protective devices and switches integral to the Company EPS within the Generator-Owner's or IC's facility.

2. Sequence of events recorders shall be installed to log events such as limiter operation and protective trips (target logs) and generator performance during severe disturbances.
3. The Company or Regional ISO may, during emergency situations, implement voltage reduction as a load relief measure. The Generator-Owner or IC is responsible for any additional equipment necessary to remain on-line during such voltage reductions, refer to Section 4.0 herein.
4. Should the Generator-Owner's or IC's generator facility experience unexpected tripping of their interrupting device, the Generator-Owner or IC 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.
5. Refer to Section 2.1.1 herein and ESB 755 for other Generator-Owner or IC operating responsibilities.

## 6.0 REVISION HISTORY

<u>Version</u>	<u>Date</u>	<u>Description of Revision</u>
1.0	06/01/07	Initial version of new document superseding all previous revisions of ESB 756.
1.1	09/06/11	Permit study of DG on area networks in Section 1.1, no other technical changes, only formatting and general editing based on September 2010 ESB 750 Series Errata changes.
1.2	09/22/14	Added reference in Section 2.2.1.2 to ESB 751 released in June 2014. Editorial correction to Table header in Section 4.5.2.8.5.
2.0	08/03/17	June 2017 major revision incorporating NY, MA, RI, NH, and VT jurisdictions and good utility practice changes.



## **Electric System Bulletin No. 756 Appendix B:**

# **Distributed Generation Connected To National Grid Distribution Facilities Per The New York State Standardized Interconnection Requirements**

**June 2017 version 4.0**

ESB 756 Appendix B is part of the ESB 750 series

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## 1.0 Purpose

1. Electric System Bulletin (ESB) 756 Appendix B covers requirements for interconnecting customers proposing to install a distributed energy resource (DER) system (“Customer-Generator”) to National Grid’s (the “Company”) upstate NY electric power system (EPS) for State jurisdictional projects.
2. ESB 756 Appendix B does not cover the technical state and federal transmission operator jurisdictional requirements (NY ISO and FERC) for connection to the Company’s transmission EPS, community microgrids, and parallel operated DER systems and on-site generators (OSG) larger than 5 MW that are covered by the Company’s ESB 756 Appendix A.<sup>1</sup>
3. This ESB supplements **ESB 750** and the New York State Standardized Interconnection Requirements and Application Process For New Distributed Generators 5 MW or Less Connected in Parallel with Utility Distribution Systems (**NY SIR**) and provides general technical requirements, recommendations, and assistance to customers regarding DER systems, having an aggregate nameplate rating of 5 MW or less, connected in parallel to the Company’s distribution EPS. The NY SIR does not apply to DER systems larger than 5 MW. 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.
4. ESB 756 and this Appendix B are available on the Company’s website at <http://www.nationalgridus.com/electricalspecifications> and in printed form by contacting either of the Call Centers in Massachusetts or New York (see inside cover of ESB 750 for Customer Service Center telephone numbers). However, since printed copies may not reflect the latest updates, please refer to the Company’s website for the latest authorized versions.

## 2.0 Scope

1. This Appendix B to ESB 756 is provided to assist a Customer-Generator desiring to interconnect a generator facility to National Grid’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 covered by the NY SIR connected to the Company’s EPS that are net metered generation sources (“Net Metered Classes”) 2 MW or less or non-net metered generation sources with a nameplate rating of 5 MW or less including other distributed energy resources (DER) such as energy storage systems (ESS), facility or campus-style microgrids, and where DER owners, or DER owners as clients of registered aggregators, sign onto a retail tariff with the intent to sell energy or ancillary services to the retail market. For FERC jurisdictional projects connected to the Company’s distribution EPS, the technical provisions of this document also apply in conjunction with ESB 756 Appendix A. Where conflicts arise, the technical provisions of ESB 756 Appendix B take precedence.
3. These requirements apply only to those points in which the Customer-Generator and the Company have a mutual interest in the DER facility’s or premises’ wiring service connection to ensure safety to the public and the Company employees as well as satisfactory operation,

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<sup>1</sup> For wholesale tariff requirements, please refer to the following New York independent system operator (“NYISO”) websites: [http://www.nyiso.com/public/markets\\_operations/services/planning/documents/index.jsp?doc\\_s=interconnection-studies/other-interconnection-documents](http://www.nyiso.com/public/markets_operations/services/planning/documents/index.jsp?doc_s=interconnection-studies/other-interconnection-documents), [http://www.nyiso.com/public/markets\\_operations/documents/technical\\_bulletins/index.jsp](http://www.nyiso.com/public/markets_operations/documents/technical_bulletins/index.jsp), and [http://www.nyiso.com/public/markets\\_operations/documents/manuals\\_guides/index.jsp](http://www.nyiso.com/public/markets_operations/documents/manuals_guides/index.jsp).

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compatibility, and reliability with the electrical supply to others served by the Company's EPS. This includes, but is 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 respective jurisdictional electricity tariffs. See 90.2(B)(5) in the National Electrical Code® (NEC) and the Company's ESB 750 for more information.

4. For the NY State jurisdictional requirements of the NY SIR, please refer to the retail tariff requirements at the following Company website:  
NY: [https://www9.nationalgridus.com/niagaramohawk/business/energyeff/4\\_app-pkg.asp](https://www9.nationalgridus.com/niagaramohawk/business/energyeff/4_app-pkg.asp)
5. 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 not covered by the NYS Renewable Portfolio Standard (NYS RPS), including but not limited to energy storage systems, 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-Generator's DER system 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 "Standard for Distributed Resources Interconnected with Electric Power Systems"
  - Underwriters Laboratories (UL) Std. 1741 "Inverters, Converters and Charge Controllers for Use in Independent Power Systems"
  - 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-Generator's DER system shall also conform to any applicable requirements of the NYS DPS 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 EPS equipment.
3. The Customer-Generator shall comply with the appropriate Company ESB or Electricity 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<sup>2</sup>
- **ESB 752** - Service Above 15,000 volts
- **ESB 753** - Primary Meter Pole
- **ESB 754** - Outdoor Pad Mounted or Vault Enclosed Single and Three Phase Transformer
- **ESB 755** - Operation & Maintenance Requirements for Services Above 600 Volts
- **ESB 758** - Primary Service to Metal Enclosed Gear
- **PSC 220** - Niagara Mohawk Power Corporation's Electricity Rate Tariff
- **PSC 220, Rule 53** - Standard Interconnection Requirements for OSG's 5 MW or Less Connected in Parallel with Utility Distribution Systems

Refer to **Exhibits 4** and **5** and **Figures 1** through **4** for information when submitting single-line diagrams to the Company's electronic mail address at DistributedGenerationServices-NY@nationalgrid.com.

## 4.0 Definitions

See ESB 750, ESB 756, Rule 53 of the [Electricity Tariff](#), and the NY SIR 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.
2. **Certified DER:** A UL 1741 certified inverter.
3. **Generator:** Equipment that produces power.
4. **Generator Set or Genset:** The singular assembly of an electrical generator and a prime mover.
5. **Line section:** Any EPS circuit segment that can be isolated via an automatic interrupting device such as a sectionalizer, recloser, or circuit breaker.
6. **Non-certified DER:** Any non-UL 1741 inverter, induction or synchronous DER.
7. **Prime Mover:** The mechanical 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.
8. **Recloser:** A line protective device having automatic interruption and controlled reclosing characteristics.
9. **Utility Grade:** Refers to protective device equipment complying with ANSI/IEEE C37.90, ANSI/IEEE C37.90.1 and ANSI/IEEE C37.90.2.

## 5.0 Customer-Generator Interface Procedures

### 5.1 Application Process Overview

This section outlines the process for a Customer-Generator to receive Company approval to interconnect DER systems to the Company's distribution EPS. This process is intended for the following:

1. New DER systems with a nameplate rating of 5 MW or less, as aggregated on the customer side of the point of common coupling (PCC), that are eligible under the NY SIR process and;
2. Review of any modifications affecting the Company's distribution EPS and service connection interface at the PCC of existing Customer-Generator DER systems that:
  - (i) Have a nameplate rating of 5 MW or less as aggregated on the customer side of the PCC;
  - (ii) Are eligible under the SIR process; and
  - (iii) Have been connected to the Company's EPS where an existing interconnection agreement and/or power purchase agreement between the Customer-Generator and the Company is in place.

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<sup>2</sup> ESB 751 Applies regardless of service voltage for Distributed Energy Resources (DER).

This application process and its requirements do not apply to generation equipment that will never be allowed to operate in parallel with the Company's 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's EPS and have no provision for such connection (even for a short period of time).

#### **5.1.1 DER Applicant Technical Data Submission**

The Customer-Generator shall submit, at the time of application, all relevant technical documentation as indicated in the [NY SIR](#). The Company reserves the right to request additional information as needed specific to the interconnection of Customer-Generator equipment including, but not limited to, three line diagrams, control diagrams, equipment test reports and other information; see the Company's ESB 751<sup>3</sup>.

##### **5.1.1.1 Control Diagrams**

The Customer-Generator 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.

##### **5.1.1.2 Interconnection Facility Equipment Data Sheets**

The Customer-Generator shall submit all technical data associated with the specific distribution, protection, and generation equipment included in the project. Submitted documentation shall highlight product numbers and information for the specific equipment/devices that will be installed as part of the project.

##### **5.1.1.3 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. Interfacing transformer(s)
2. Interrupting device(s)
3. Isolation devices(s) (e.g. Generator Disconnect)
4. Point of Common Coupling (PCC)
5. Company pole number nearest to the proposed PCC
6. Existing and proposed access road(s) including, at a minimum, road material, and dimensions to confirm Company personnel and equipment access requirements are met.
7. Restricted accesses, fences, gates and access controls.
8. Generator location
9. Existing service(s)

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.

##### **5.1.1.4 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:

- Method of ESS connection whether: (1) ESS directly connected to utility EPS; (2) DER and ESS DC coupled; (3) DER 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.

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<sup>3</sup> ESB 751 Applies regardless of service voltage for Distributed Energy Resources (DER).

- Sequence of operation for the charging and discharging capabilities of the ESS and the maximum ramp rate in Watts/minute.
- Non-UL 1741 listed inverters will require a utility intertie relay with the appropriate IEEE 1547 functions, settings, and islanding protection according to the Company's **ESB 756** jurisdictional requirements.

#### **5.1.1.5 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. Facility or campus-style microgrid applications have certain characteristics described here, all of which fall under the U.S. Department of Energy (DOE) definition.<sup>4</sup>

Such microgrids consist of one or more buildings and the relationship with the connection to the Company's EPS 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 Company.

These facility or campus-style microgrids are premises wiring systems governed by the NEC as adopted by the local jurisdictional authority.<sup>5</sup>

## **5.2 Interconnection Process – Non Expedited**

The process for installation of those facilities the Company deems necessary for interconnection of the DER system will be specified by the Company in response to the Customer-Generator's application. See **Exhibit 1** for Company Requirements for Projects Not Eligible for the Expedited Process.

## **5.3 Objectives in the Application Process**

1. Parallel operation of a generator becomes a part of the Company's EPS whereby the Customer-Generator and the Company have a mutual interest in ensuring that the interconnection meets the required electrical reliability and security 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 NY SIR.
2. Additional site-specific requirements may be indicated once the supply voltage, service arrangement, location, and generation purpose is determined, where such purpose can be:
  - peak shaving,<sup>6</sup>
  - net metering, remote net metering,

<sup>4</sup> 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."

<sup>5</sup> See NFPA 70-2017, National Electrical Code® (NEC) for installation requirements of premises wiring systems related to microgrids.

<sup>6</sup> Peak shaving generation is customer-owned generation operated in parallel with the Company's EPS to reduce a customer's electrical demand. Unlike net metering, peak shaving generation, if not authorized under "behind the meter" NY ISO programs (see ESB 756 Appendix A), is not permitted to flow into the utility supply system upstream of the billing meter and will require the installation of protection devices (e.g., reverse power relays) 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.

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- DER value stack metering (e.g. demand response, energy storage, renewable energy), or
  - export energy with an agreement for sales<sup>7</sup> according to the Company's Electricity Tariff provisions.
3. For new electric service or modifications to the electric service connection to accommodate the Customer's parallel generator, refer to the Company's latest revision of ESB No. 750, Specifications for Electrical Installations. The Customer-Generator 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 NY Building Code requirements, the Customer-Generator will need to provide evidence of electrical inspection approval from their local code enforcement agency for their premises wiring installation.
    - The Customer-Generator will also be responsible for any additional costs associated with work completed by another entity (such as telephone company pole sets). The Customer-Generator should be aware that project construction schedules can be severely impacted by this other work.
  4. When considering a new or modified DER interconnection arrangement, the following forms in the Company's [Electricity Tariff](#) are required to be submitted to the Company as applicable:
    - "Form "K" Appendix A Niagara Mohawk Power Corporation d/b/a National Grid New York State Standardized Contract for Interconnection of New Distributed Generation Units with Capacity of 5 MW or Less Connected in Parallel with Utility Distribution Systems."
    - For non-net metered applications, "General Information for Connection of On-Site Generators Application for Electric Standby Service Form "G"."
  5. Any subsequent sale of an On-Site Generator (OSG) facility covered by the requirements of the NY SIR will require the new owner to establish a separate interconnection agreement (Form K) for the generation with the Company and comply with these parallel generation requirements.
  6. Refer to:
    - The steps to install DER systems in New York as specified in the [NY SIR](#),
    - The Company's [Electricity Tariff](#),
    - The Company's Distributed Generation Services **electronic mail address** for general inquiries: [DistributedGenerationServices-NY@nationalgrid.com](mailto:DistributedGenerationServices-NY@nationalgrid.com), and
  - The Company's Distributed Generation's web site when making an application with the Company to interconnect a DER system with additional information and specific forms as follows: <https://ngus.force.com/s/>
  7. The application process and attendant services are offered by the Company on a non-discriminatory basis to any Customer-Generator. As part of the process, the Company may identify the need for detailed engineering studies (Coordinated Electric System Interconnection Review or CESIR), EPS upgrades and additional protection requirements. As allowed by the NYS DPS and the Company's [Electricity Tariff](#), the costs of the detailed study and upgrades are the responsibility of the Customer-Generator. If the Customer-Generator makes significant changes in the design or installation scheduling of their DER system, then any previous information furnished by the Company to the Customer-Generator is subject to review and possible change, which may cause a delay in service.
  8. A CESIR report presents the analysis results of the Company's interconnection study based on the proposed interconnection and service plan submission from the Interconnection Customer. The intent of this report is to assess the project's feasibility, determine its impact

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<sup>7</sup> An Agreement for Sales of Export Energy under a NY SIR application may be made per the Company's [Electricity Tariff](#), Service Classification No. 6, and is a Power Purchase Agreement (PPA).

on the existing power system, determine interconnection scope and installation requirements, and determine costs associated with interconnecting the Interconnection Customer's generation to the Company's EPS.

9. In accordance with the current NYSSIR document, National Grid will review and study the proposed Interconnection Customer's distributed generation (DER) project to determine:
  - if the project meets the applicable criteria considered in the CESIR process,
  - if the addition of the DER to the Company's EPS results in any system impacts, such as relay coordination issues, changes in fault current that affect equipment ratings, voltage regulation problems, or changes to electric system operation,
  - if the generation, as proposed, presents any potential to "island" existing load presently being served from the Company's EPS,
  - if the generation, as proposed, can effectively re-synchronize after an outage to either the Company EPS, or an outage to the generator,
  - a good faith, detailed estimate of the total cost of completion of the interconnection of the proposed system, and the Customer's cost responsibility for the required interconnection equipment.
10. The **CESIR** does not address the future operations and maintenance (O&M) associated with National Grid's distribution system.

#### **5.4 Considerations During the Application Process for DER Interconnections in Secondary Grid and Spot Network Areas**

1. When applying for a DER system to be interconnected within the Company's secondary area network and secondary spot network EPS located in the downtown districts of Albany, Buffalo, Cortland, Glens Falls, Niagara Falls, Schenectady, Syracuse, Troy, Utica, or Watertown, DER system installations on distribution secondary network systems may require a study to be undertaken by the Company regardless of size, type or complexity to ensure that the DER system does not degrade the reliability, power quality, safety, or operation of the Company's network system. Therefore, customers in the downtown districts of Albany, Buffalo, Cortland, Glens Falls, Niagara Falls, Schenectady, Syracuse, Troy, Utica, or Watertown **should contact the Company at [DistributedGenerationServices-NY@nationalgrid.com](mailto:DistributedGenerationServices-NY@nationalgrid.com)** to determine if the proposed location is served by a distribution secondary network system. This should be done while the DER system is still in the planning stage, and certainly before purchasing equipment or beginning installation. The Company will review the Customer-Generator's plans and discuss options with the customer. Refer to attached **Exhibit 2** for area maps locating the Company's secondary network service area and the following link for more specific information  
<https://ngus.force.com/s/article/ka10W00000wnRaQAI/Upstate-NY-Secondary-Area-Network-and-Secondary-Spot-Network-Maps>
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.
  1. 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. National Grid'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.

2. 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 Institute of Electrical and Electronics Engineers (IEEE) Std. 1547.
3. As a result, the connection of customer DER systems on networks **(i)** poses some issues for the Company to maintain adequate voltage and worker safety and **(ii)** has the potential to cause the reverse power flow on network feeders affecting network protector operation within the network grid. Therefore, to ensure network safety and reliability additional information will be required for the Company's engineering analysis such as:
  - Customer's existing<sup>8</sup> or proposed electric demand profile showing minimum load during peak generation time,
  - Customer-Generator's expected generation profile shown for a 24-hour period and typical 7-day duration based on nameplate generation rating, and
  - Customer-Generator'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.

### **5.5 Interconnection Charges**

Customer-Generators shall be subject to charges for interconnection costs. To permit interconnected operations with a Customer-Generator, the Company may incur costs which are in excess of those it would have incurred had the customer taken standard load service. These incremental costs are directly related to the installation of those facilities the Company deems necessary for the interconnection of the DER system. They include initial engineering evaluations, purchase and installation of additional switching, transmission and distribution equipment at Company's facilities, additional safety provisions, engineering and administration. These costs shall be paid in full by the Customer-Generator prior to commencement of service in accordance with the Company's [Electricity Tariff](#), and the NY SIR. For typical Company interconnection cost items expected to support those proposed DER systems not eligible for the Expedited Process as defined in the NY SIR that will be defined in a CESIR, see tables 5.5-1 and 5.5-2 which are not intended to be all inclusive. Costs will be determined according to the Company's [Electricity Tariff](#) and the NY SIR.

1. Payment requirements of the CESIR estimate are outlined in the NY SIR. The Company will reconcile all charges to reflect actual cost responsibilities upon project completion. In the event final charges are greater than the CESIR estimate, the Interconnection Customer will be responsible for all final charges. In the event the final charges are lesser than the CESIR estimate, the Company will reimburse excess charges.
2. The Company's Customer Energy Integration department shall be consulted for the Interconnection Customer's payments in accordance with the Company's filed tariffs, NMPC [PSC No. 220](#).

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<sup>8</sup> 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-Generator will be according to the Company's electric customer load survey flat rate and charged in accordance with the terms of the Company's [Electricity Tariff](#) and NY SIR.

**Table 5.5-1: DER Projects Not Eligible for the Expedited Process where no EPS upgrades are expected**

Item No.	Typical Company Support Activities Attributed to Customer-Generator's Project (Requiring Charges to the Customer)	Electricity Tariff Rule References
1	Engineering acceptance review of DER 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.	24, 36, 37, 53
2	Revenue metering equipment changes/additions.	25, 36, 37, 53
3	Field audit of DER Customer's installation to accepted design.	24, 36, 37, 53
4	Field compliance verification - witness tests of Customer-Generator's protective devices coordinating with the Company's Distribution EPS.	24, 36, 37, 53
5	Project Management	53

**Table 5.5-2: DER Projects Not Eligible for the Expedited Process (Complex)**

Item No.	Typical Company Support Activities Attributed to Customer-Generator's Project (Requiring Charges to the Customer)	Electricity Tariff Rule References
1	Distribution EPS upgrades (e.g., Current Limiting Fuses, Primary Conductors, Line Reclosers, Switches, Voltage Regulators, Capacitors, etc.) as a result of DER system impact.	15-18, 28, 36, 37, 53
2	Where Local EPS anti-islanding protection is required, DTT transmit addition to Distribution EPS substation feeder breaker (and/or Line Recloser) for DER system impact on distribution feeder.	28, 36, 37, 53
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 system impact on distribution feeder.	28, 36, 37, 53
4	Where Local EPS feeder selectivity may require prompt control measures for DER system impact on distribution feeder operations, EMS-RTU (status & control) addition at the DER system's facility.	28, 36, 37, 53
5	Service Connection modifications and additions for DER system impact on the Company's Distribution EPS.	19-23, 28, 36, 37, 53
6	Engineering acceptance review of Customer-Generator'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 system) according to the Company's ESB 750 series.	24, 28, 36, 37, 53
7	Revenue metering equipment changes/additions.	25, 28, 36, 37, 53
8	Field audit of Customer-Generator's installation to accepted design.	24, 28, 36, 37, 53
9	Field compliance verification - witness tests of Customer-Generator's protective devices coordinating with the Company's Distribution EPS.	24, 28, 36, 37, 53
10	Project Management	28, 53

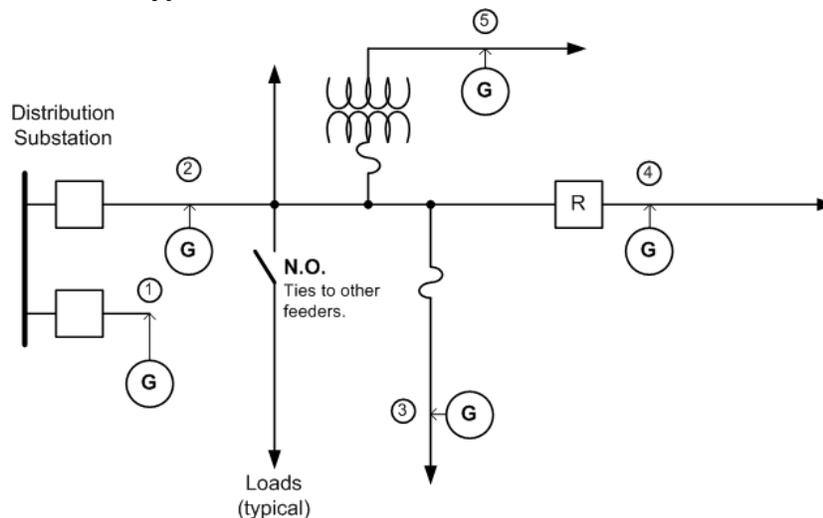
## 6.0 Potential Issues Related to Interconnection

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 of 5 MW or less located individually on higher capacity feeders may not cause very serious impacts whereas those located on weaker circuits, in aggregation or in special cases (such as lightly loaded networks), can significantly impact the Company's distribution EPS.
2. A CESIR in some cases is needed to identify the severity of system impacts and the upgrades needed to avoid problems on the Company's EPS. Typically, a CESIR 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 systems to the Company's EPS including, but not limited to:
  - a. Impact on step voltage regulation equipment

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- 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 voltages
  - 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's EPS so that any negative impacts to the Company's EPS performance can be avoided and without degradation of EPS safety and reliability. It is the intent of any Company study in accordance with SIR 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, DER facilities connected to various locations on the EPS (see Illustration 6.5-1) are initially evaluated for the maximum possible DER capacity under ideal situations that can be installed on the Company's EPS through technical screens in the NY SIR. 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 according to the NY SIR and will identify the interconnection requirements.

**Illustration 6.5-1: Typical DER 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 major EPS infrastructure. The Company will

identify DER saturation in screening and feasibility reviews and in the results of impact studies for DER applications. Studies will be more complex and accommodating interconnections will likely require more involved infrastructure development, costs, and duration to construct.

1. 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.
2. 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.
7. The Company's substations are subject to fault duty limitations. Adding generation to the Company's EPS increases the amount of fault current imposed on the substations and equipment located 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 systems will not be permitted and alternate methods of interconnection shall be explored or the replacement at the expense of the Customer-Generator of "overduty" equipment and devices with the appropriate ratings and of Company standard design where this limit has been reached.

## 7.0 General Design and Operating Requirements

From the perspective of interconnection, there are three main types of Customer-Generator systems that interface to the 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 CESIR that is performed for a specific DER system and/or location. For the purposes of this bulletin, any reference to DER ratings herein refers to the nameplate rating of the generation facility.

- 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-Generator's manufacturer with a permanent means of reducing the rated output, and so marked with an equipment nameplate stating the de-rated output.
- For rotating machines, this shall refer to the nameplate rating of the generator (as opposed to the nameplate rating of the generator-set or prime mover). De-rating of rotating machine generators by their prime mover capabilities shall not be permitted.
- Equipment nameplates shall meet ANSI standards. De-rating of DER facility equipment shall be evaluated on a case-by-case basis, with consideration given to specific project conditions, and will be accepted at the sole 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 and specifications 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 NY SIR 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 NY SIR. Each specific connection must be studied with respect to size, type, and the nature of the EPS at the interconnection point. Only the results of a specific study can indicate the suitability of a given DER system connection to the Company's EPS and its possible economic viability. See Rule 53 of the [Electricity Tariff](#) and the [NY SIR](#) for detailed requirements.

### **7.1.1 Single Phase**

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

- 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.
- Configured as a three-wire, line-to-line with neutral, or line-to-neutral with adequate load balance.
- A dedicated service lateral with a dedicated transformer, when required by the Company.

### **7.1.2 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 shall not exceed 5 MW covered by the NY SIR. For greater than 5 MW, refer to ESB 756 Appendix A.

### **7.1.3 Phase Balance and Voltage Tolerance**

1. The Customer-Generator'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%.

### **7.1.4 Neutral Stabilization, Ground Fault, and Grounding**

1. Where the Customer-Generator is served from a Company multi-grounded distribution circuit, an effectively grounded system with respect to the Company's EPS must be provided to ensure neutral stability and avoid distribution circuit over voltage during accidental isolation of the Company's area EPS from the main Company system. This may require an additional ground source. Adequate grounding can be provided either by the use of wye grounded-delta main power transformer or by an appropriate grounding means (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 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:
  - The winding arrangement of the Customer's generation facility transformer and the generator winding shall be such that the Company's system remains effectively grounded (see Section 7.3).
  - The Company may require that 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-Generator's interconnection. Hence, it is required

that the Customer-Generator provide a means to install a grounding reactor/resistor within their facility to limit the ground fault current. Where possible, the ground fault current 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-Generator to mitigate the increase in fault current.

- If the Customer-Generator is permitted to interconnect through an un-grounded source, a “zero-sequence” voltage or “ $3V_0$ ” scheme will be required on the primary side of the approved delta primary wound transformer (see Figure 4) supplying the DER system.
3. As a minimum, the Customer-Generator’s DER system equipment shall be grounded in accordance with the latest requirements of the National Electrical Code (NEC). For specific installations, refer to the applicable sections of this document and the Company’s ESB 750.

## **7.2 Service Equipment and Revenue Metering**

### **7.2.1 Service Equipment Requirements**

1. The Customer-Generator shall provide service entrance equipment as a part of their installation; see the Company’s ESB 750. The Customer-Generator’s service equipment shall be rated, at a minimum, for the maximum fault current available from the Company’s EPS and their own contribution from the generator(s), motors, etc.
2. Permanent Plaques: At the service entrance equipment, the Customer-Generator shall have a permanent directory plaque to indicate all electric sources and the generator disconnect location(s) on their premise in accordance with the NEC.
3. For large DER Customers with aggregate generation equal to or greater than 500 kW, refer to the typical primary overhead service configuration requirements in **Exhibit 5**.
4. For situations where a higher voltage service connection is required, refer to the Company’s ESB 752, 753, or 758 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-Generator’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 NY SIR and Rule 53 of the [Electricity Tariff](#) describe qualifications for net 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<sup>9</sup> for parallel import connections to prevent reverse billing meter registration. When applicable, credit metering will be installed if arrangements have been made for energy sales to the Company under a PPA; see Service Classification No. 6 of the [Electricity Tariff](#).
2. Customer-Generators may be required to provide a telecommunication line to each Company-owned revenue meter location. This telecommunication line would only be required in the event a cellular signal was not sufficient to provide reliable service 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 facsimile machines, etc.

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<sup>9</sup> “Detented metering” is measuring and registering power flow in a single direction by either mechanical, or electronic, or programming means in a revenue meter.

## **7.3 Transformer**

### **7.3.1 Secondary Served Customer-Generators**

Where the Company provides secondary service, the Company's transformer is standard for service delivery voltages offered in the Company's [Electricity Tariff](#); see Section 3 in [ESB 750](#). Maximum transformer size the Company will supply for a new secondary connected DER connection is 500 kVA where the non-DER premises electricity use is 500 kVA or less. 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-Generator's DER facility's life cycle. If a dedicated transformer(s) is required, the Customer-Generator will be advised by the Company in writing. The cost of the transformer(s) will be the responsibility of the Customer-Generator according to the [Electricity Tariff](#) and as permitted by the NY SIR. 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.
2. Interconnection of DER to the customer side of the transformer creates undesirable effects on the Company's EPS.
3. 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.
4. Existing transformer configuration is such that an additional primary side protection scheme is needed for the DER facility to detect and trip the generation source for faults on the Company's EPS that requires the Customer-Generator to have primary service.

### **7.3.2 Primary and Higher Voltage Served Customer-Generators**

The Company reserves the right to specify the winding connections for the Customer-Generator's interconnect transformer between the Company's delivery point and the Customer-Generator's DER system output terminals as well as whether it is to be grounded or ungrounded. The Customer-Generator shall provide their interconnection transformer's specifications and ratings for the Company's review and acceptance in the CESIR process.

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

To avoid overvoltage on the distribution EPS and other customers, the Company's policy requires any DER facility 500 kW and above connected to a four-wire multi-grounded distribution feeder to provide an effectively grounded system with respect to the Company's EPS.

The Company requires that the Customer-Generator selects their interface transformer's winding configurations so that the DER system is interconnected effectively grounded. The Customer-Generator's DER facility shall be designed such that it cannot connect to the Company's 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 facility shall be disconnected from the Company's EPS.

Aggregate DER below 500 kW in a Customer-Generator's facility may be permitted to utilize a primary delta - 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 at 250 kW and above depending on DER saturation and other conditions on individual distribution EPS feeders.

Effective grounding may be accomplished with the following configurations:

1. A wye-grounded to wye-grounded transformer with a grounded generator source.
2. A wye-grounded connected primary winding with a fully insulated neutral and the secondary winding to have a delta connection. 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.
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.
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.

**7.3.2.2 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 Disconnect Switch**

1. Inverter-based DER systems 25 kW and below are not required to have a separate manual generator disconnect switch if the unit has a disconnecting means integrated into the design and meets the requirements of the NEC.
2. For those DER systems requiring a manual generator disconnect switch, these isolation devices shall meet applicable UL, ANSI, and IEEE standards, and shall be installed to meet the NEC and all applicable local, state, and federal codes.
3. The Customer-Generator's DER facility shall have an 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-Generator shall provide contact information for their qualified personnel that can be reached 24/7, should complications arise with access to the Customer-Generator's equipment. The Company will make efforts whenever possible to notify the Customer-Generator should the DER facility need to be de-activated; however, the Company reserves the right to operate the DER facility's disconnect directly in emergency situations. Should there be any complications with Company access to the DER facility's disconnecting device, the Company reserves the right to disconnect the Customer-Generator's service in its entirety by the next upstream Company-owned isolation means when absolutely necessary.

For installations above 600 V, the location of the DER facility disconnecting means shall comply with Company requirements for working clearances, access road construction, vegetation management, and other similar requirements to ensure adequate access for Company operating personnel and equipment. Should the disconnecting means be located behind the Customer-Generator's locked gate, double locking is required, where both the Company's and Customer-Generator's locks would be employed.

4. 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 applying protective grounds as needed, performing maintenance, and repair work. The designated generator disconnect also must be accessible and lockable in the open position and have provisions for both Company and Customer-Generator padlocks. 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-Generator 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.

5. The visible generator disconnect switch must be a blade-type switch meeting the requirements of the NEC and nationally recognized product standards. Pull-out switches or blocks are not permitted for this application.
6. The connection of the disconnect switch shall have the line connection (i.e., jaw side) of the switch made to the utility source. Hinge side of switch shall be connected electrically towards the customer.
7. This disconnect device shall be identified by a permanent sign as required in accordance with the NEC and the NY SIR.

## **7.5 Generator Interrupting Device Requirements**

### **7.5.1 General**

1. The generator interrupting device shall be designed to ensure the interrupting of the DER system upon loss of interrupting device supply power, or upon loss of local power supply source.
2. When a local power supply source is utilized, generator interconnection interrupting devices shall have DC trip coils and tripping energy.
3. 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 interconnection transformer, this requirement applies to each one individually.

### **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.
4. System design calculations in accordance with IEEE standards and other industry standards as applicable shall be provided by the Customer-Generator for supply voltage, capacity specifications, and charging system provisions and are subject to the Company's review and acceptance.
5. Control circuits associated with protective relays shall be DC powered from a battery and battery charger system. Solid state relays shall be self-powered or DC powered from a battery and battery charger system.

6. 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 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-Generator 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-Generator's system that cause overcurrent conditions on the Company's EPS.

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

### **7.6.1 Type Tested (Certified) Equipment**

Protective equipment that has been type tested and recognized by the NY SIR will be permitted. See the NYS DPS' list of certified interconnection equipment on their website at: <http://www3.dps.ny.gov/W/PSCWeb.nsf/All/DCF68EFCA391AD6085257687006F396B?OpenDocument>. The Customer-Generator shall follow the testing requirements as outlined in Rule 53 of the [Electricity Tariff](#) and the [NY SIR](#). Refer to Exhibit 6 for a guide for the Company's witness for verifying a type tested net-metered DER system' operational compliance.

### **7.6.2 Non-Type Tested Equipment**

Protective equipment that has not been type tested per the NY SIR will be permitted with the implementation of utility grade protective devices acceptable to the Company. The use of utility grade relays<sup>10</sup> is subject to prior Company review and acceptance per section 7.6.3.2.

### **7.6.3 Number of Relays Required**

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 EPS at service voltages less than 15 kV, a single utility grade microprocessor-based relay along with a Company approved scheme, where relay failure automatically trips the associated breaker(s), is acceptable. If the Customer-Generator decides not to use redundant protection systems on their 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 initiate trip to the Company-designated generator interrupting device. Auxiliary relays, where used, shall be fail safe and utility grade.

#### **7.6.3.1 Certified Inverter-based Energy Resource Protection Requirements**

IEEE 1547 compliant and UL-1741 certified<sup>11</sup> 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 and its amendments ("IEEE 1547"). The amendment to the standard, IEEE 1547a, requires voltage and frequency ride through capabilities be available in all inverter based generation. The Customer-

<sup>10</sup> See definition of "utility grade" for protective device equipment in Section 4.

<sup>11</sup> See definition for "certified" in Section 4.

Generator shall provide the voltage and frequency ride through capabilities as specified in IEEE 1547a in any inverters installed as part of a DER facility proposed to interconnect to the Company's EPS. The voltage regulation and ride-thru capabilities shall be turned OFF unless otherwise required by the Company.

#### **7.6.3.1.1 Individual Certified Inverter-based Energy Resources below 500 kW**

If the inverter is IEEE 1547 compliant and UL-1741 listed, the internal relays are considered as the only required protection and an additional utility grade relay is not necessary to be installed. At the Company's sole discretion the Company reserves the right to require a utility grade relay for systems above 300 kW with, at minimum, functions 27, 59, 81U/O and voltage controlled overcurrent 51C.

#### **7.6.3.1.2 Individual Inverter-based Energy Resource 500 kW or Above**

IEEE 1547 compliant and UL-1741 listed inverter internal relay functions are considered as primary protection. The Company requires one additional utility grade relay to be installed as secondary protection for inverter-based solar PV generation 500 kW and above. The 27, 59, 81U/O, voltage controlled phase overcurrent 51C, and 51N or 51G elements shall be activated in the secondary protection relay. The Customer-Generator 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. The relay failure alarm shall be wired to initiate trip to the Company designated generator interrupting device. If two utility grade relays are used to provide the above functions, failure of either relay, or both, being out of service shall trip the interrupting device.

### **7.6.3.2 Non-Certified Energy Resource Protection Requirements**

#### **7.6.3.2.1 Energy Resources below 500 kW**

For non-certified generators less than 500 kW one utility grade relay installed as primary protection is required. At minimum the 27, 59, and 81 U/O functions shall be active in this relay. For systems 300 kW or larger, the Company reserves the right to require additional protective elements to be active.

### **7.6.4 Instrument Transformers for Protective Device Relays**

#### **7.6.4.1 Current Transformers (CT)**

CT ratios and accuracy classes shall be chosen such that secondary current is less than or equal to 5 amperes under normal operation and 100 amperes under maximum fault conditions. For the primary wye grounded – secondary delta installations, the CTs shall be installed on the primary voltage side. If the interconnection transformer is primary wye grounded – secondary wye grounded, the CTs can be installed on either the primary or secondary voltage 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. Meter selector switches shall not be connected into the secondary circuits of current transformers used with protective relays specified by the Company.

#### **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) for effectively grounded circuits. 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 Company's EPS, and the secondary voltage is within the relay's acceptable operating range, a direct voltage connection may be acceptable and VTs may not be required. The use of Yg-broken Delta VTs will be considered by the Company on a case-by-case basis.

### **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. Interposing computer-based or programmable logic controllers, auxiliary modules, or the like are prohibited 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.

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 86 lockout relay functions) 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. DC inputs or outputs are not permitted on AC test switches.

- AC Inputs: Each relay shall have its own AC test switch.
- DC Inputs and Outputs: For relays designated by the Company 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.
- *Exceptions*:
  - *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.*

*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 relay, test switches shall not be required.*

### **7.6.7 Voltage Relay Devices**

Over and under voltage relays shall meet IEEE 1547 requirements including capability for under voltage ride through. See Table 7.6.12.1-1 below for default voltage relay settings.

### **7.6.8 Frequency Relay Devices**

Over and under frequency relays shall meet IEEE 1547 requirements including capability for under frequency ride through. The under-frequency trip setting shall not conflict with the under-frequency load shedding schemes on the Company's EPS. For adjustable under frequency settings in IEEE 1547, the chosen setting shall fall below the generator under frequency trip modeling curve of NERC PRC-006-2. See Table 7.6.12.1-1 below for default frequency relay settings.

### **7.6.9 Synchronizing Devices**

The Customer-Generator 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-Generator's DER facility will island and then synchronize back to the Company's EPS.

### **7.6.10 Overcurrent Relay Devices**

Overcurrent protection is required to detect faults on the Company’s EPS, as well as faults on the Customer-Generator’s system that cause overcurrent conditions on the Company’s EPS. Overcurrent elements are required for both phase and ground. For inverter-based systems, a voltage controlled phase element (51C) is required. These relays shall utilize voltage sensing with Yg-Yg VTs specified in section 7.6.4.2.

**7.6.11 Utility Grade Protective Device Settings and Verification**

**7.6.11.1 Default Voltage and Frequency Set points for all types of 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 Parallel Generation Default Voltage & Frequency Set points**

DEVICE	PICKUP RANGE	TIME DELAY RANGE (sec)	DEFAULT TIME DELAY (sec)
Under Frequency 2 (81U)	$\leq 56.5$ Hz	$\leq 0.16$	0.16
Under Frequency 1 (81U)	$\leq 58.5$ Hz	$> 2$	300
Over Frequency 1 (81O)	$\geq 61$ Hz $\leq f < 62.0$ Hz	0.1-300.0	300
Over Frequency 2 (81O)	$> 62$ Hz	$\leq 2$	0.16
Under Voltage (27)	$< 50\%$ of Nominal	0.1 – 11.0	0.16
Under Voltage (27)	$50\% \leq V < 88\%$ of Nominal	0.1 – 21.0	2
Over Voltage (59)	$110\% < V < 120\%$ of Nominal	0.1 – 13.0	1
Over Voltage (59)	$\geq 120\%$ of Nominal	0.16	0.16

Settings other than the default 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.

**7.6.11.2 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 (kW)	Max. Frequency Difference ( $\Delta f$ , Hz)	Max. Voltage Difference ( $\Delta V$ , %)	Max. Phase Angle Difference ( $\Delta \Phi$ , degrees)
0-500	0.3	10	20
>500 – 1,500	0.2	5	15
>1,500 – 10,000	0.1	3	10

**7.6.11.3 Company-designated Relays and Customer-Generator Settings**

1. The Company will review the Customer-Generator’s settings and the calibration and test results of those relays that the Company designates as being required to satisfy the Company’s 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 prior written consent of the Company.

**7.6.11.4 Company Verification of Relay Testing**

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

- control wiring verified against the accepted design drawings, and
- 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-Generator may propose alternative methods of anti-islanding protection of their own generation facility, although it is the Customer-Generator'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 National Grid 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 voltage or provide Var support functions. Any inverter type generation established as voltage regulating or Var supportive will be reviewed under section 7.6.12.4 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  $\leq 33\%$  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 National Grid'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
  - a. DER  $\geq$  300 kW and DER > 33% minimum load and is connected to < 5 kV EPS.
  - b. DER 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<sup>12</sup>
  - a. If line faults (phase and ground where applicable) cannot be cleared by DER protective device or the Company's PCC recloser.<sup>13</sup>
  - 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.

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-Generator's property for the PCC recloser installation serving their DER facility. See Figure 5 for a typical one-line configuration of a PCC recloser primary metered overhead service.

#### 7.6.12.3 Certified DER<sup>14</sup>

1. All inverters shall have an 88% voltage trip within 2 seconds to be considered in this section.
2. Proposed DER rated  $\leq$  50 kW
  - a. No requirements.
3. Proposed DER rated > 50 kW and < 1000 kW
  - a. Line section aggregated non-certified DER is  $\leq$  10% of mix.
    - i. No additional requirements.
  - b. Line section aggregated non-certified DER is > 10% and  $\leq$  25% of aggregate DER.
    - i. Sandia screening<sup>15</sup> may be applicable depending on inverter models on segment.

<sup>12</sup> While the intent of this unintentional islanding protection policy is to encourage DER installations while minimizing inhibitive impacts to the DER installation, National Grid reserves the right and flexibility to enforce protective measures deemed required for the safety and reliability of the EPS.

<sup>13</sup> 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).

<sup>14</sup> Inverter firmware derating is not acceptable for reduction of system size to satisfy thresholds within this document.

<sup>15</sup> Sandia screens (<http://energy.sandia.gov/wp-content/gallery/uploads/SAND2012-1365-v2.pdf>) are valid only for certified inverters that have been confirmed, in writing from the manufacturer, to meet the definition of the Sandia Frequency Shift (SFS), or Sandia Voltage Shift (SVS) as positive feedback based methods or for inverters using impedance detection with positive feedback. SFS and SVS both rely on positive feedback to work.

- ii. Company-owned PCC recloser and reclose blocking required if Sandia screens not passed.
  1. Detailed risk of islanding (ROI) study may be performed at the Customer-Generator's request. If results of the detailed study show no significant risk of islanding for a period greater than 2 seconds, then the recloser and reclose blocking is waived.
- c. Line section aggregated non-certified DER is > 25% of all DER.
  - i. NG PCC recloser and reclose blocking required<sup>16</sup>
    1. Detailed ROI study may be performed at the Customer-Generator's request. If results of the detailed study show no significant risk of islanding for a period greater than 2 seconds, then reclose blocking is waived. Company-owned PCC recloser is waived for aggregate DER  $\leq$  67% of line load to generation ratio or < 500 kW.
4. Proposed DER rated DER  $\geq$  1000 kW
  - a. Company-owned PCC Recloser required.
  - b. Reclose blocking required if line segment aggregate DER > 50% of minimum load.

#### **7.6.12.4 Non-certified & voltage regulating inverters, induction & synchronous machines**

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

### **7.7 Monitoring and Control (M&C) at DER Facility**

DER ranging from 300 kW and above may require supervisory control and data acquisition (SCADA) communication for visibility to the Company's energy management system (EMS) and to incorporate the ability for the Company's system operators via EMS 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.

1. The Company requires an RTU for status and control of the generator for the following conditions:
  - 300 kW or greater for DER systems connected to the Company's EPS of 5 kV or below.
  - 1 MW or greater for DER systems connected to the Company's EPS greater than 5 kV but less than 15 kV.
  - 1.8 MW or greater for DER systems connected to the Company's EPS greater than 15 kV but less than 35 kV.

Where a PCC recloser is required or requested and approved, this EMS-RTU requirement is waived, since SCADA requirements will be extracted from the Company's PCC recloser for EMS purposes.

EMS-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. For example, situations

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

<sup>16</sup> *Where feasible, installing a PCC recloser in front of the non-certified DER may reduce or eliminate any further requirements to the subject applicant DER.*

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where an RTU may be required could occur where there is EPS feeder selectivity operation or significant current on a line section for switching procedures.

The control portion would only involve the remote trip of the Customer-Generator's interrupting device(s) designated by the Company. When a remote RTU trip command is issued the local DER interrupting device must be designed for reset through a manual process and is subject to review by the Company for acceptance.

2. The required inputs from the RTU to the Company's EMS shall be as follows:

- Status of individual generator breaker(s)
- Status of main or interconnect breaker at the PCC
- Control input for the "designated generator interrupting device"
- Three phase line current for each generator
- Three phase line current at the PCC with the Company
- Three phase line-to-line voltage for each generator
- Three phase line-to-line voltage at the PCC with the Company
- Output kW for each unit (+ delivered to the Company, - received)
- Output kVAR for each unit (+ delivered to the Company, - received)
- Total MW (+ delivered, - received) at the PCC
- Total MVAR (+ delivered, - received) 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 RTU point list for inputs required at the DER system.*

3. When a Company 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-Generator will be responsible for all initial and recurring costs associated with communications for this RTU. General requirements for the RTU installation in the Customer-Generator facility are, but not limited to:

1. The RTU cabinet is typically 42" H x 30" W x 26" D and shall be wall, pole or strut mounted with the bottom edge 36" above the floor. A 5-foot clear working space shall be maintained in front of the mounting panel.
2. A dedicated 20A, 120VAC, single phase 60 hertz power circuit is required for the RTU cabinet. All conduit and wiring (minimum of No. 10 AWG copper) to the telemetry cabinet for this circuit shall enter the cabinet from the bottom. A three (3) foot length of all conductors shall be provided for final Company connection.
3. The Customer-Generator will be responsible for mounting this equipment in their installation, subject to Company approval. The Customer-Generator will provide space, power, and all input connections for this package.
4. The following guidelines shall be adhered to:
  - 1) The RTU shall be remote from heavy traffic areas, work areas and loading areas.
  - 2) The RTU shall be remote from heat producing or high electrostatic or electromagnetic field producing equipment.
  - 3) The analog inputs to the RTU shall be +1.0mA DC at rated input, +2ma DC maximum; see Section 8.4.2 above.
5. For telecommunication provider steps and requirements:
  - 1) The local serving telephone company's facilities demarcation and equipment shall be located as close to the RTU cabinet and protection relays, as feasible, relative to the Customer-Generator's mutually agreed upon location.

- 2) The Customer-Generator is responsible for arranging the installation and paying all costs associated with required telecommunication line(s) for all RTU and tele-protection circuits (e.g., DTT) including maintenance and recurring telephone company charges as documented in the interconnection study or interconnection agreement.
  - 3) The Customer-Generator shall be responsible for all telephone company coordination, installation, final connections, and commissioning of all required telecommunication circuits.
  - 4) The Customer-Generator is responsible to complete telephone company's form requirements such as high voltage protection (HVP) form when arranging for the telecommunication service. The technical information normally provided includes, but not limited to: total square footage area of Ground Grid/Mat, Grid Impedance (in Ohms) to Remote Earth, total expected Fault Current (line-to-ground) in Amps RMS (or Amps Peak), Earth Return Current (as % of Total Fault Current), X/R Ratio, and Soil Resistivity (layer depth information in feet).
  - 5) The Customer-Generator is responsible to comply and coordinate with their telephone company's commissioning process of telecommunications circuits required with the Company.
4. Where a Company PCC recloser is installed, the Company will utilize the PCC recloser serving the DER facility to obtain Company's SCADA operational monitoring polling data and control.

## **7.8 Voltage and Frequency Control**

1. Inverter based generators shall be in compliance with all revisions of IEEE 1547. The amendment to the standard, IEEE 1547a, requires voltage and frequency ride through capabilities be available in all inverter based generation. The Customer shall provide the voltage and frequency ride through capabilities specified by IEEE 1547a in any inverters installed as part of a generator proposed to interconnect on the Company EPS.
2. These capabilities shall be disabled by default unless otherwise approved by the Company.

## **8.0 Testing and Commissioning**

1. The Company reserves the right to witness the Customer-Generator's testing of the required devices.
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-Generator shall submit a testing and commissioning plan (TCP) to the Company for review at least twenty (20) business days prior to the scheduled witness test. If needed, consult the Company for guidance on preparing a TCP.*
5. All required equipment test reports shall be submitted per ESB 751 prior to final TCP acceptance.
6. The TCP shall be finalized as accepted by the Company no later than five business (5) days prior to functional testing of the Company-designated protective devices.

## **9.0 Operating**

1. The DER system shall maintain a power factor at the PCC in accordance with the NY SIR; at or between 0.90 leading or lagging (Var or voltage support can also be considered within machine ratings). Corrective equipment may be required and, if so, it will be at the Customer-Generator's expense; refer to ESB 750. It is the Company's expectation that the Customer-Generator will strive to maintain a power factor at their service point that does not adversely affect the power quality (PQ) ("PQ") of the Company's EPS; see ESB 750.

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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 Interconnection Customer is responsible for the operation and maintenance of their facilities up to the demarcation point of the Interconnection Customer's service on the Customer's property in accordance with the Company Bulletins.
4. The Customer-Generator 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-Generator operating and maintenance responsibility
5. Should the Customer-Generator's DER facility experience unexpected tripping of their interrupting device, the Customer-Generator 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.

## 10.0 Power Quality Monitoring

### 10.1 Power Quality Compliance Verification

If during the study the interconnection of a DER system is identified as having the potential to cause PQ effects on the Company's EPS, then PQ monitoring shall be installed by the Company or Company-accepted third party PQ testing company to verify PQ 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](#) and the limits and cost responsibilities specified in the NY SIR:

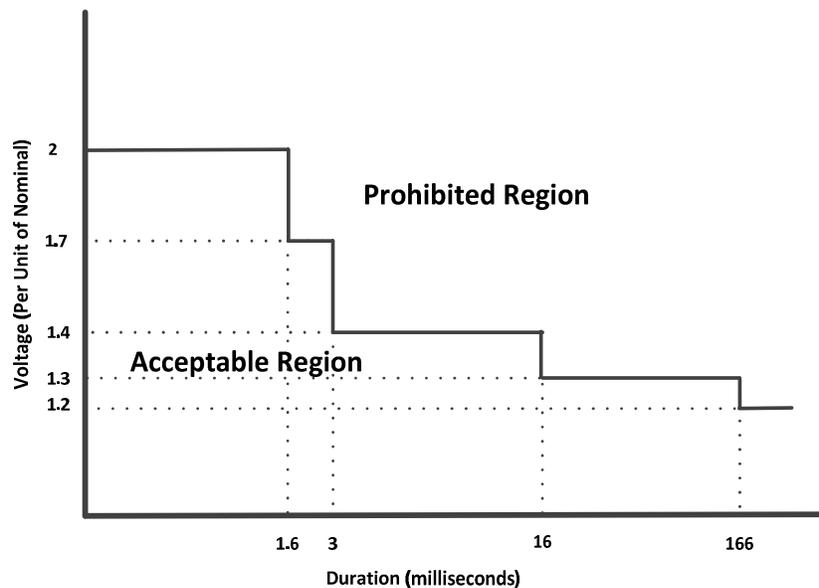
- Check service point voltage for any discernible voltage fluctuation.
- Check service point frequency for any discernible frequency fluctuation.
- Check PCC power factor to ensure it is no less than 90% (leading or lagging).
- Check service point harmonic distortion to ensure limits specified in ESB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

### 10.2 Power Quality Disturbance and Mitigation

1. If disturbances on the Company's Distribution EPS and/or to other customers are suspected to originate from a customer with an installed DER system, PQ monitoring shall be installed to verify power quality in accordance with the Company's [Electricity Tariff](#).
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 customers DER installation cannot be immediately corrected, the Customer-Generator **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 adhere to the Transient Over-voltage Tolerance curve as defined in Figure 10.3-1.



**Figure 10.3-1: Transient/Temporary Overvoltage Tolerance Curve**

IEEE 1547 settings require that an inverter-based DER ceases to energize the EPS in 160ms (10 cycles) for an overvoltage of 1.2 per unit (pu) or greater of nominal voltage. This trip point is inadequate to prevent damage to utility and customer equipment depending on the magnitude of the overvoltage per Figure 10.3-1 above. These issues could affect the inverter-based DER facility, as well as affect utility and other customer equipment on the feeder.

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 acceptable 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 Figure 10.3-1. The letter shall be on the manufacturer'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 shall reserve the right to periodically audit the Interconnection Customer's generation equipment installation and service connection for compliance with the Company's requirements.

## 12.0 Disconnection by the Company (Isolation)

The Company reserves the right to have the Customer-Generator remove their DER system from the Company's EPS at any time upon the Company's request. Normally, such requests result from the need to facilitate maintenance, testing, or repair of Company facilities. The Customer's generator disconnect switch<sup>17</sup> may be opened by the Company (isolating the Customer's generating equipment), without prior notice to the Customer-Generator, for any of the following reasons:

- System emergency operations require such action.

<sup>17</sup> Refer to Section 7.4 regarding technical requirements for draw-out breakers over 600 V and the Company's *Electricity Tariff* for limitations of service.

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- Company periodic checks of Customer-Generator'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 NY SIR testing of type tested inverters, prior to Company approval to interconnect.
- Failure to make available records of verification tests and maintenance of the Customer-Generator's protective devices designated by the Company.
- 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

<u>Version</u>	<u>Date</u>	<u>Description of Revision</u>
1.0	06/01/07	Initial version of new document superseding all previous revisions of ESB 756.
2.0	09/06/11	Revise for Dec. 2010 NY SIR.
3.0	09/22/14	Revise for Apr. 2013 & Feb. 2014 NY SIR and technical updates in Sections 4, 5, and 6.
4.0	08/03/17	June 2017 revise for Apr. & Nov. 2016 and Feb. 2017 NY SIR and changes in National Grid protection practices.

## EXHIBITS ATTACHED

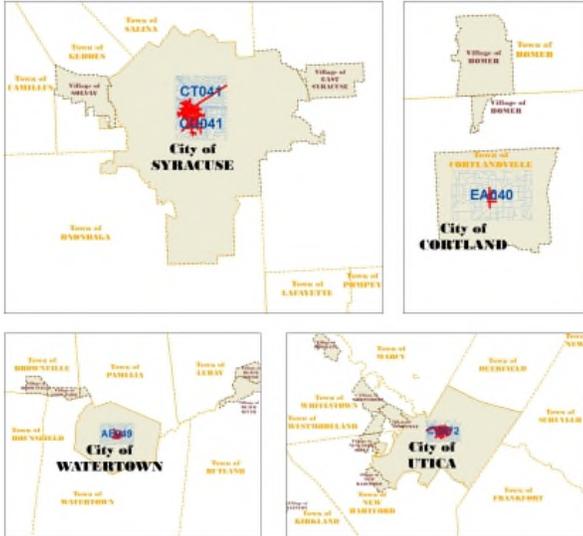
## ***EXHIBIT 1: Company Requirements for DER Systems Not Eligible for the Expedited Process***

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

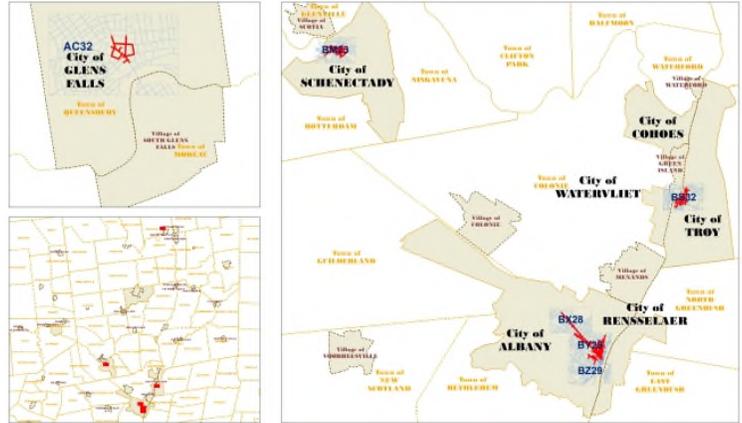
<b>ID</b>	<b>Activity Description</b>	<b>NY SIR §I.C / ESB ref.</b>
<b>Project Definition &amp; Conceptual Analysis Phase</b>		
1	Customer-Generator Form K w/technical submittal & prelim. design received	Steps 1 - 3
2	Company Preliminary Technical Assessment & cost estimate for CESIR	Step 4
3	Company Form K Interconnection Agreement and Form G as needed are executed with Customer-Generator	Step 5
4	Customer-Generator commits to final CESIR and provides advance payment	Step 5
<b>Preliminary Design Review Phase</b>		
ESB 751 Stage A		
5	Customer-Generator's preliminary project schedule, design, specifications, test reports, and protective device settings received.	Step 6
6	Company final CESIR and Interconnection Service Plan with Planning Grade construction estimate	Step 6
7	Company reviews Customer-Generator preliminary design & returns comments	Step 6
<b>Final Design Review Phase</b>		
ESB 751 Stage B		
8	Customer-Generator commits to utility system modifications in CESIR & Interconnection Service Plan and provides advance payment	Step 7
9	Customer-Generator's project schedule, final design, specifications, & protective device coordination analysis received	Step 7; ESB 750 & 752 or 753 or 754 or 758
10	Company reviews Customer-Generator's design & returns comments	Step 8; ESB 752 or 753 or 754 or 758
<b>Installation Progress Review Phase</b>		
ESB 751 Stage C		
11	Customer-Generator's corrected design, test reports, & protective device settings received	Step 8; ESB 752 or 753 or 754 or 758
12	Company reviews Customer-Generator's design & returns comments	Step 8; ESB 752 or 753 or 754 or 758
<b>Installation Compliance Verification Phase</b>		
ESB 751 Stage D		
13	Customer-Generator's advance notice of functional testing received	Step 9; ESB 755
14	Electrical inspection certification approval received from municipal or AHJ authorized 3 <sup>rd</sup> party agency	ESB 750 & 752 or 753 or 754 or 758; Local AHJ
15	Customer-Generator's acknowledgement of satisfactory wiring & relay calibration tests received	Steps 9 & 10; ESB 755
16	Company witness of Customer-Generator's functional testing	Step 10; ESB 755
17	Company field audit of Customer-Generator's service connection	Steps 8 - 10; ESB 750 & 752 or 753 or 754 or 758
18	Customer-Generator resolves open compliance verification items	Steps 8 - 10; ESB 750 & 752 or 753 or 754 or 758
19	Verification testing satisfied	Steps 9 & 10
<b>Energization &amp; Synchronization Phase</b>		
ESB 751 Stage E		
20	Company's metering installation complete	Steps 8 - 10; ESB 750 & 752 or 753 or 754 or 758
21	Customer-Generator's energization sequence plan received for interconnections > 600 V	Steps 9 & 10; ESB 755
22	Company's supply system interconnection complete	Steps 9 & 10
23	Company review/acceptance of Customer-Generator's resolved open items in 18 above.	Steps 9 & 10
24	Company proceeds with energization	Steps 9 & 10
25	Customer-Generator is permitted to synchronize generation facility in parallel to the Company's supply	Step 10
<b>Project Closeout Phase</b>		
ESB 751 Stage F		
26	For interconnections > 600 V, remainder of Customer-Generator's protective system functional testing documented in an acknowledgement letter submitted to the Company within 10 business days after energization	Step 11; ESB 755
27	Customer-Generator's as-built design drawings received within 90 days for interconnections > 600 V	Step 11; ESB 750 § 1.7
28	Company reconciliation of project costs with Customer-Generator within 90 days of as-built documents received.	Step 11

## ***EXHIBIT 2: Reference Maps of National Grid upstate NY Secondary Network EPS Areas***

### **NY Central Division**



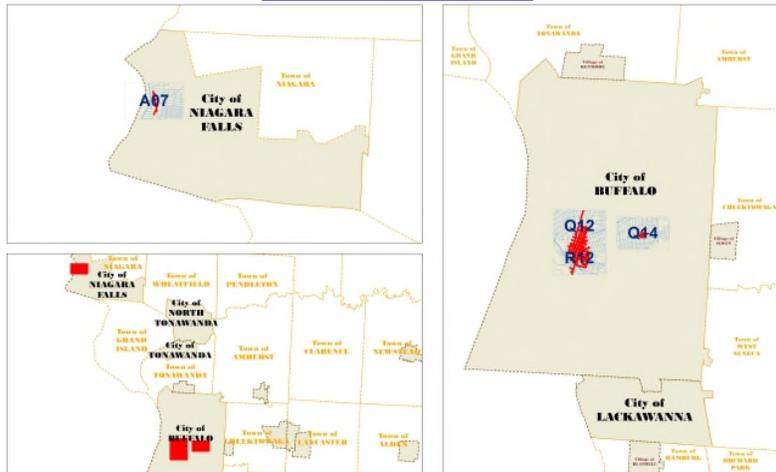
### **NY Eastern Division**



National Grid customers in the downtown districts of Albany, Buffalo, Cortland, Glens Falls, Niagara Falls, Schenectady, Syracuse, Troy, Utica, and Watertown can refer to the following Internet web site to view maps of National Grid's Secondary Networks and determine if the proposed location is served in those areas.

[http://www.nationalgridus.com/niagamohawk/home/energyeff/4\\_networkmap.asp](http://www.nationalgridus.com/niagamohawk/home/energyeff/4_networkmap.asp)

### **NY Western Division**



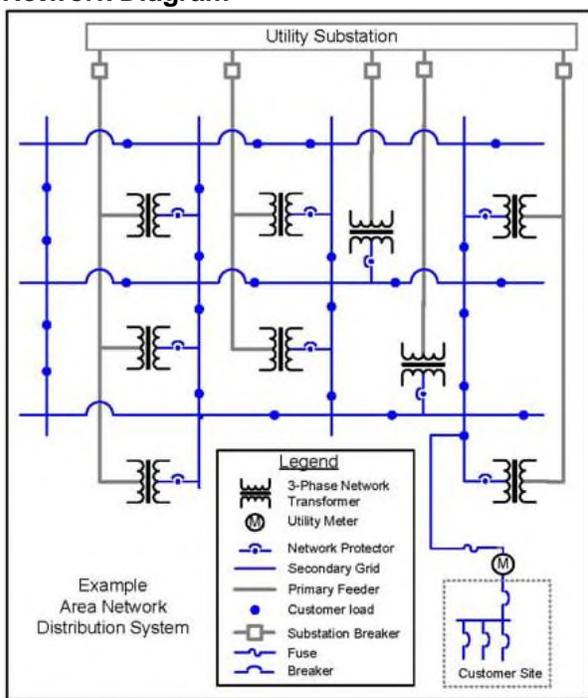
### EXHIBIT 3: Distribution Secondary Grid and Spot Network Description

In Upstate New York, National Grid 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 Albany, Buffalo, Cortland, Glens Falls, Niagara Falls, Schenectady, Syracuse, Troy, Utica, and Watertown are served by distribution secondary network systems; see Exhibit 3 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.

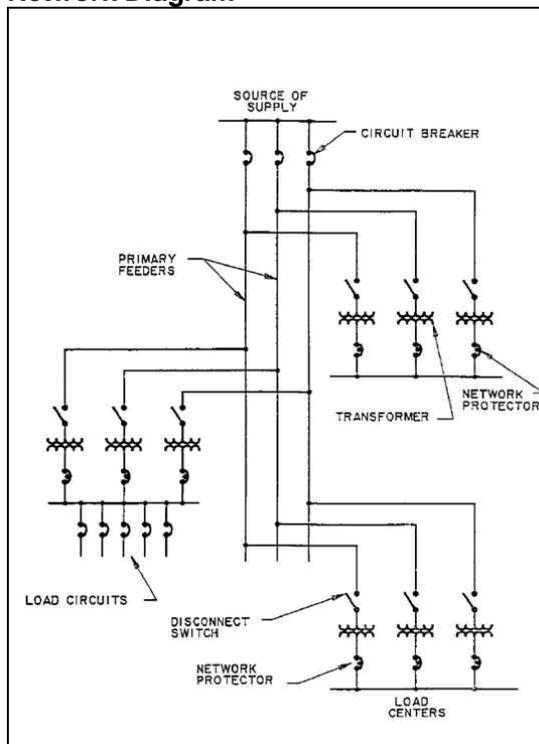
In distribution secondary network systems, devices called "network protectors" are usually arranged to automatically connect its associated transformer to the network system when conditions are such that the transformer when connected will supply power to the network and to automatically disconnect the 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 Grid 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 Spot Network Diagram



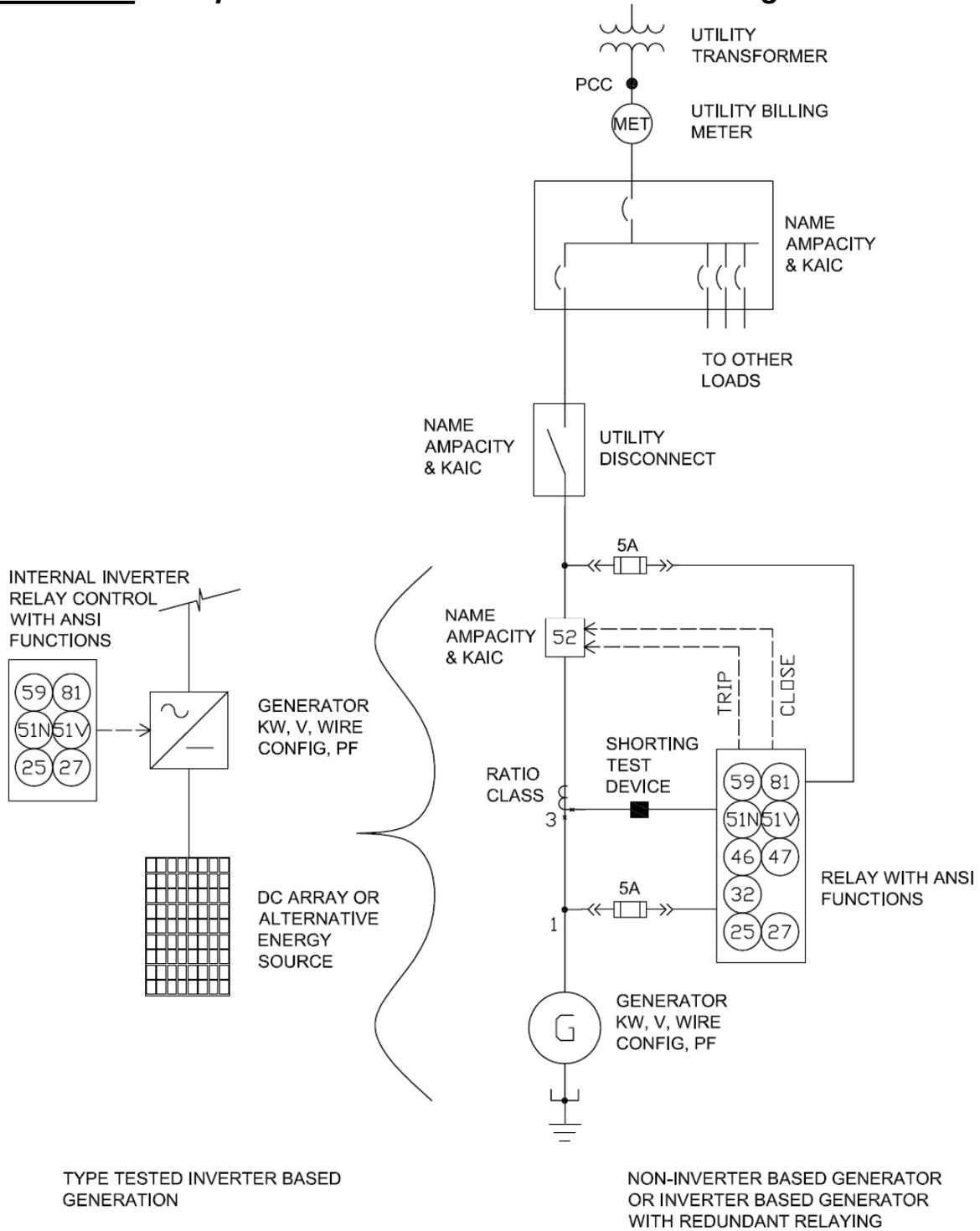
Spot networks are similar to grid (area) networks except they serve a single premise.

## ***EXHIBIT 4: Recommended Guidelines for Residential and Commercial Single-line Diagram Submittals***

Refer to **Figures 1** and **2** 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.
11. Show connections and ratings of power transformer windings for any to be used.
12. Identify Generator Disconnect and its ratings, the service point, and the PCC.
13. 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-Generator. 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 Distributed Generator One-Line Diagram**



[TYPICAL ONLY]

**FIGURE 2: Typical Symbolology for Electrical Drawings**

ELEMENTARY SWITCH DEVICES								CONTACTS AND RELAYS	
FLOW		PRESSURE		LIQUID LEVEL		TEMPERATURE		CONTACTS	
CLOSED RISING	OPENS RISING	CLOSED RISING	OPENS RISING	CLOSED RISING	OPENS RISING	CLOSED RISING	OPENS RISING	NORMALLY OPEN OR "a" CONTACT	NORMALLY CLOSED OR "b" CONTACT
LIMIT				PUSHBUTTON		RELAY COIL			
NORMALLY OPEN	NORMALLY OPEN - HELD CLOSED	NORMALLY CLOSED	NORMALLY CLOSED - HELD OPEN	NORMALLY OPEN	NORMALLY CLOSED				
ELEMENTARY FUSE DEVICES			BATTERY OR DC SOURCE			CONNECTIONS			
FUSE	SOLID LINK	IN REMOVABLE CARTRIDGE OR PULL BLOCK	GENERAL OR SINGLE CELL	MULTI CELL (COMMON)	GROUND	SHORT CIRCUIT (3-PHASE CONNECTION)	SEPARABLE CONNECTORS OR DRAW OUT FEATURE		
DISCONNECTS (UNDER 600 V)		CIRCUIT BREAKERS			TRANSFER SWITCH				
NON-FUSED DISCONNECT	FUSED DISCONNECT	GENERIC OR AIR TYPE	CB OR INTERRUPTING DEVICE (OTHER THAN AIR)		TWO POSITION	THREE POSITION			
CAPACITOR	ANTENNA	THERMAL OVERLOAD	INDICATING LIGHT * = LENS COLOR:						
			A - AMBER B - BLUE C - CLEAR G - GREEN O - ORANGE P - PURPLE R - RED W - WHITE Y - YELLOW						
TRANSFORMERS AND INSTRUMENT TRANSFORMERS									
3-PHASE, WYE		3-PHASE, DELTA					3-PHASE ZIGZAG		
GROUNDING NEUTRAL	UNGROUNDING	DELTA	CORNER GROUNDING	OPEN DELTA	OPEN DELTA CORNER GROUNDING	BROKEN DELTA	UNGROUNDING	GROUNDING	
GENERIC TWO WINDING TRANSFORMER	GENERIC THREE WINDING TRANSFORMER, TERTIARY TYPE		EXTERNAL TO BUSHING	BUSHING MOUNTED	FUSED POTENTIAL TRANSFORMER				
			■ OR ● OR ×						
			CURRENT TRANS. WITH POLARITY MARKS SHOWN						

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

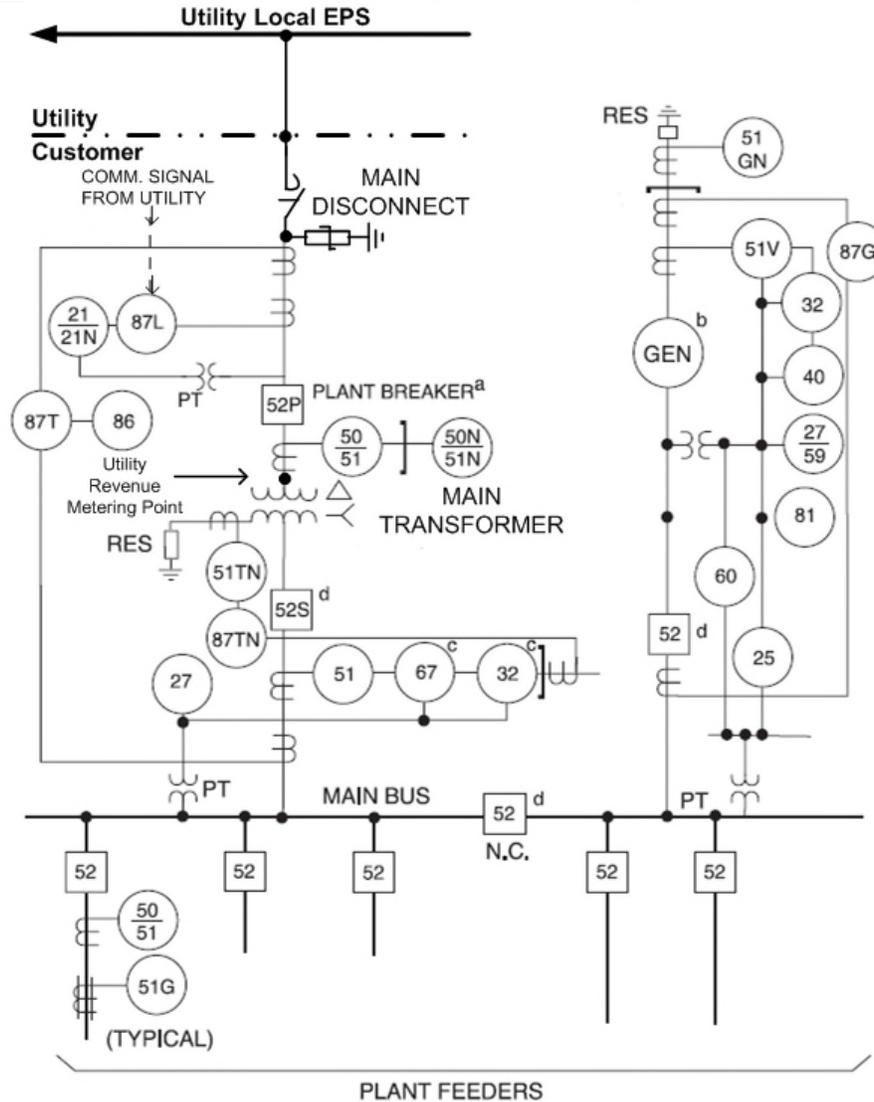
Refer to **Figures 3** and **4** for typical illustrations.

In addition to **Exhibit 5**:

14. 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**):

<b><u>Device Number</u></b>	<b><u>Function</u></b>
25	Synchronizing Device / Synchronism Check
27	Under Voltage Relay
32	Directional Power Relay
46	Negative Sequence Voltage
50	Instantaneous Overcurrent Relay
51	Phase Overcurrent Relay
51C	Voltage Controlled Overcurrent Relay
51G	Ground Overcurrent Relay
51N	Neutral Overcurrent Relay
51V	Overcurrent Relay, voltage restraint
52	Breaker
52R	Recloser
59	Over Voltage Relay
59G	Neutral Voltage Relay
59N	Zero Sequence Voltage Relay
62	Time-delay Stopping or Opening Relay
64	Ground Protective Relay
79	AC Reclosing Relay
81	Over and Under Frequency Relay
86	Locking - Out Relay
87	Differential Relay

**FIGURE 3: Sample Functional Single-Line Diagram**



- NOTES:
- a. A fused interrupter 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.

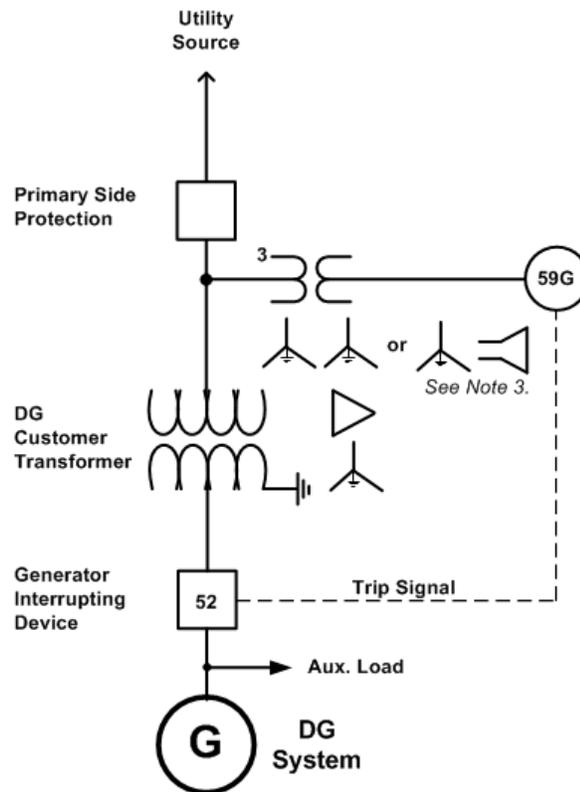
[TYPICAL ONLY]

**FIGURE 4: 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.

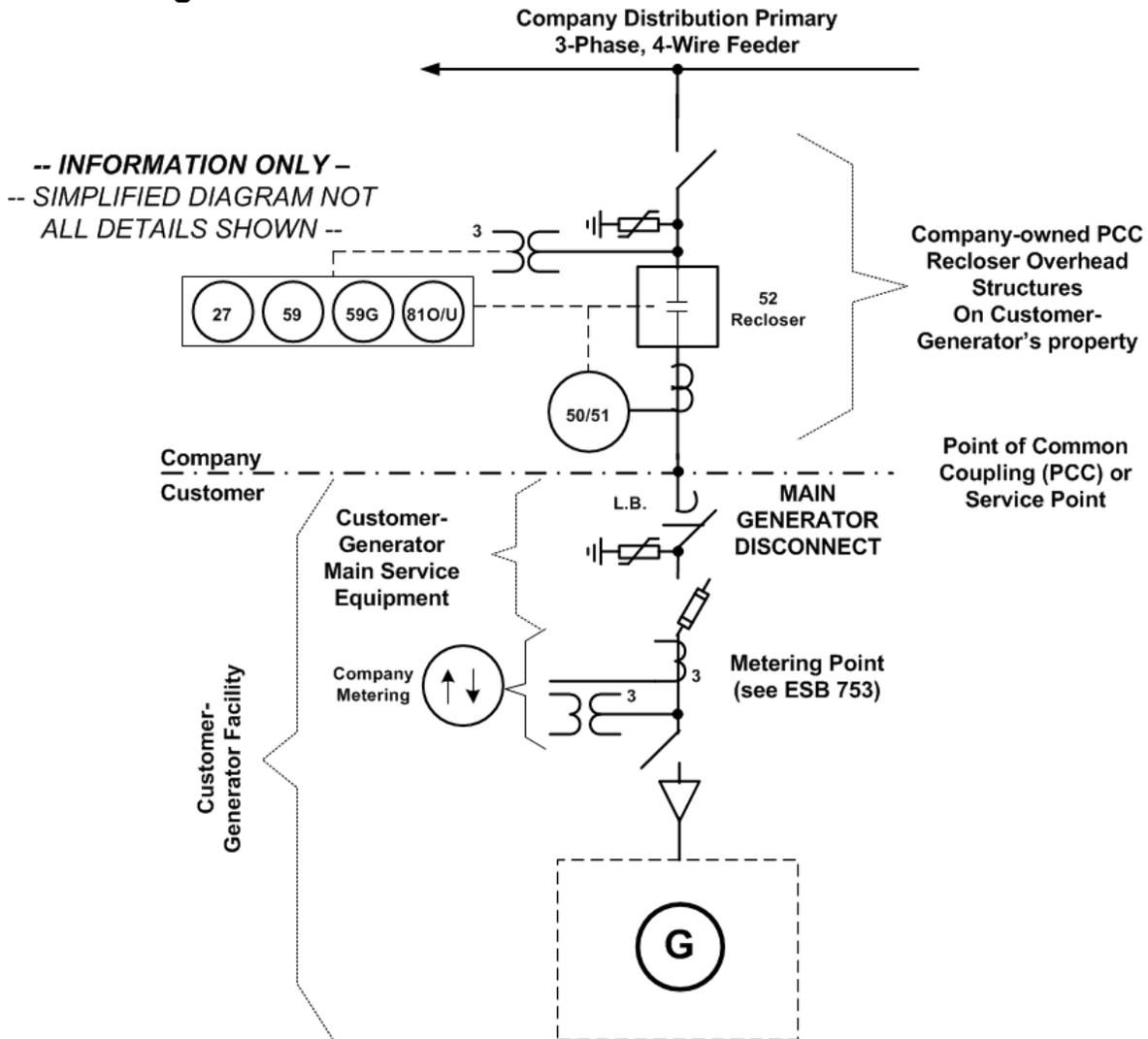
**Notes:**

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 --

**FIGURE 5: Typical Overhead Single Primary Service Configuration in NY for Large DER Installations**



**Notes:**

The Customer-Generator will be required to install a Primary Meter Pole service to the Company's specifications on which the Company will dead end the Company's primary service conductors and connect to the main disconnect switch. This point will be the physical PCC. See the Company's ESB 753 for installation specification requirements.

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

## **EXHIBIT 6: Net Metering Compliance Verification Checklist**

**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)

# **Electric System Bulletin No. 756 Appendix C:**

## **Distributed Generation Connected to National Grid Distribution Facilities per the Massachusetts Standards for Interconnecting Distributed Generation**

**June 2017 Version 4.0**

ESB 756 Appendix C is part of the ESB 750 series

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### 1.0 Purpose

1. Electric System Bulletin (ESB) 756 Appendix C covers requirements for interconnecting customers proposing to install a distributed generator (DER) system (“Interconnecting Customer” or “Customer” or “Customer-Generator”) to National Grid’s (“the Company”) Massachusetts electric power system (EPS) for State jurisdictional projects.
2. ESB 756 Appendix C does not cover the technical federal and state transmission operator jurisdictional requirements (ISO-NE and 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.<sup>1</sup>
3. This ESB supplements **ESB 750** and the Massachusetts Standards for Interconnecting Distributed Generation (**MA SIDG**) and provides general technical requirements, recommendations, and assistance to customers regarding DER systems connected in parallel to the Company’s distribution EPS. Note that the SIDG does not apply to DER units larger than 20 MW. 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.
4. ESB 756 and this Appendix C are available from the Company’s website at <http://www.nationalgridus.com/electricalspecifications> and in printed form by contacting either of the Call Centers in Massachusetts or New York (see inside cover of ESB 750 for Customer Service Center telephone numbers). However, since printed copies may not reflect the latest updates, please refer to the Company’s website for the latest authorized versions.

### 2.0 Scope

1. This Appendix C to ESB 756 is provided to assist a Customer-Generator desiring to interconnect a generator facility to National Grid’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 covered by the MA SIDG connected to the Company EPS that are net metered generation sources (Net Metered Classes) or non-net metered generation sources including other distributed energy resources (DER) such as energy storage systems (ESS), facility or campus-style microgrids, and where DER owners, or DER owners as clients of registered aggregators, sign onto a 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 also apply. Where conflicts arise, the technical provisions of ESB 756 Appendix C take precedence.

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<sup>1</sup> 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](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.

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 NEC and the Company's ESB 750 for more information.

4. For the MA State jurisdictional requirements of the MA SIDG, please refer to the retail tariff requirements at the following Company website:  
MA: [https://www9.nationalgridus.com/masselectric/home/energyeff/4\\_interconnection-process.asp](https://www9.nationalgridus.com/masselectric/home/energyeff/4_interconnection-process.asp)
5. 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 systems, 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 "Standard for Distributed Resources Interconnected with Electric Power Systems"
  - Underwriters Laboratories (UL) Std. 1741 "Inverters, Converters and Charge Controllers for Use in Independent Power Systems"
  - 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 Massachusetts DPU 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 their proposed site.
3. The Customer shall comply with 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<sup>2</sup>
  - **ESB 752** - Service Above 15,000 volts
  - **ESB 754** - Outdoor Pad Mounted or Vault Enclosed Single and Three Phase Transformer
  - **ESB 755** - Operation & Maintenance Requirements for Services Above 600 Volts
  - **ESB 758** - Primary Service to Metal Enclosed Gear
  - **M.D.P.U. 1320** - Massachusetts Electric Company Nantucket Electric Company d/b/a National Grid Standards for Interconnecting Distributed Generation (MA SIDG)
  - **M.D.P.U. 1316** - Massachusetts Electric Company Nantucket Electric Company Terms and Conditions for Distribution Service
  - **M.D.P.U. 1331** - Massachusetts Electric Company Nantucket Electric Company Net Metering Provision
  - **M.D.P.U. 1321** – Massachusetts Electric Company Nantucket Electric Company Qualifying Facility Power Purchase Rate P

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@nationalgrid.com](mailto:Distributed.Generation@nationalgrid.com).

## 4.0 Definitions

See ESB750, ESB756, and the **MA SIDG** 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.
2. **Certified DER:** A UL 1741 certified inverter.
3. **Generator:** Equipment that produces power.
4. **Generator Set** or **Genset:** The singular assembly of an electrical generator and a prime mover.
5. **Line section:** Any EPS circuit segment that can be isolated via an automatic interrupting device such as a sectionalizer, recloser, or circuit breaker.
6. **Non-certified DER:** Any non-UL 1741 inverter, induction or synchronous DER.
7. **Prime Mover:** The mechanical 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.
8. **Recloser:** A line protective device having automatic interruption and controlled reclosing characteristics.
9. **Utility Grade:** Refers to protective device equipment complying with ANSI/IEEE C37.90, ANSI/IEEE C37.90.1 and ANSI/IEEE C37.90.2.

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<sup>2</sup> ESB 751 Applies regardless of service voltage for Distributed Energy Resources (DER).

10. **Interconnection Customer and Customer-Generator** are used synonymously in this document.

## 5.0 Customer-Generator Interface Procedures

### 5.1 Application Process Overview

This section outlines the process for a Customer to receive Company approval to interconnect DER facilities to the Company's distribution EPS. 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 **MA SIDG** process and;
2. Review of any modifications affecting the Company distribution EPS and service connection interface at the PCC of existing Customer DER systems that:
  - (i) Have a nameplate rating of 20MW or less as aggregated on the customer side of the PCC;
  - (ii) Are eligible under the SIDG 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.

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 Massachusetts 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 MA SIDG contained in National Grid's Massachusetts and Nantucket electricity tariff, M.D.P.U. 1320 ([https://www9.nationalgridus.com/non\\_html/Interconnect\\_stds\\_MA.pdf](https://www9.nationalgridus.com/non_html/Interconnect_stds_MA.pdf)).

#### 5.1.1 DER Applicant Technical Data Submission

The Customer shall submit, at the time of application, all relevant documentation as indicated in MDPU 1320. The Company reserves the right to request additional information as needed specific to the interconnection of Customer-Generator equipment including, but not limited to, three line diagrams, control diagrams, equipment test reports and other information; see the Company's ESB 751.

##### 5.1.1.1 Control Diagrams

The Customer-Generator 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.

##### 5.1.1.2 Interconnection Facility Equipment Data Sheets

##### 5.1.1.3 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. Interfacing transformer
2. Interrupting devices
3. Isolation device(s) (e.g. Generator Disconnect)

4. Point of Common Coupling (PCC)
5. Company pole number nearest the proposed PCC
6. Company line extension to site and from nearest Point of Interconnection
7. Restricted accesses, fences, gates and access controls
8. 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.
9. Generator location
10. Existing service(s)

Site plans shall be to scale with approximate distances indicated. In addition to site plan, the Company may request an assessor map to determine property lines, wetlands and easements.

#### **5.1.1.4 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:

- Method of ESS connection whether: (1) ESS directly connected to utility EPS; (2) DER and ESS DC coupled; (3) DER 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.
- Sequence of operation for the ESS' charging and discharging capabilities and the maximum ramp rate in Watts/minute.
- Non-UL 1741 listed inverters will require a utility intertie relay with the appropriate IEEE 1547 functions, settings, and islanding protection according to the Company's [ESB 756](#) jurisdictional requirements.
- Service configuration and revenue metering provisions shall meet the Company's [ESB 750](#) and its applicable supplements.

#### **5.1.1.5 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. Facility or campus-style microgrid applications have certain characteristics described here, all of which fall under the U.S. Department of Energy (DOE) definition.<sup>3</sup> 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.

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<sup>3</sup> 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."

These facility or campus-style microgrids are premises wiring systems governed by the National Electrical Code (NEC) as adopted by the local jurisdictional authority.<sup>4</sup>

## 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 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 a part of the Company EPS and where the Customer and the Company have a mutual interest the interconnection is required to preserve the safety, reliability, security, power quality, and operational efficiency needs of the Company 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 **MA SIDG**.
2. Additional site-specific requirements may be indicated once the supply voltage, service arrangement, location, and generation purpose is determined, where such purpose can be:
  - peak shaving,<sup>5</sup>
  - net metering for solar, wind, or agricultural projects as under the Company's net-metering tariff, M.D.P.U. 1331, or
  - export energy for a QF with an agreement for sales<sup>6</sup> according to the Company's tariff provisions.
3. For new electric service or modifications to electric service to accommodate the Customer's parallel generator, 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:
  1. Under MA and municipal building code requirements the Customer will need to provide evidence of electrical inspection approval from their local municipal code enforcement agency.
  2. 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 M.D.P.U. 1320 Exhibit A or B application is submitted to the Company's Distributed Generation Services department.

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<sup>4</sup> See *NFPA 70-2017 National Electrical Code®* for installation requirements of premises wiring systems related to microgrids.

<sup>5</sup> *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.*

<sup>6</sup> *An Agreement for Sales of Export Energy for a QF under a MA SIDG application may be made per the Company's M.D.P.U. 1321 electricity tariff and is a Power Purchase Agreement.*

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5. Any subsequent sale of an On-Site Generator (OSG) facility covered by the requirements of the MA SIDG of the original retail Customer's facility will require the new owner to establish a separate interconnection agreement (M.D.P.U. 1320 Exhibit F and/or G) for the generation and to comply with these parallel generation requirements.
6. Refer to:
  - The steps to install distributed generation in Massachusetts as specified in the MA SIDG; see Section 3.0 of M.D.P.U. 1320 ([https://www9.nationalgridus.com/non\\_html/Interconnect\\_stds\\_MA.pdf](https://www9.nationalgridus.com/non_html/Interconnect_stds_MA.pdf)),
  - The Company's Distributed Generation Services **electronic mail address** as follows for inquiries: [Distributed.Generation@nationalgrid.com](mailto:Distributed.Generation@nationalgrid.com), and
    - The Company's ([www.nationalgridus.com](http://www.nationalgridus.com)) "Distributed Generation" web site at [https://www9.nationalgridus.com/masselectric/home/energyeff/distributed\\_generation.asp](https://www9.nationalgridus.com/masselectric/home/energyeff/distributed_generation.asp) for information and forms listed below (from M.D.P.U. 1320) [https://www9.nationalgridus.com/non\\_html/Interconnect\\_stds\\_MA.pdf](https://www9.nationalgridus.com/non_html/Interconnect_stds_MA.pdf)) when making an application with the Company:
      - Simplified Process application form and service agreement (Exhibit A)
      - 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)
      - Impact Study Agreement under the Standard Process (Exhibit E)
      - Detailed Study Agreement for the more detailed study under the Standard Process which requires substantial System Modifications (Exhibit F)
      - Interconnection Service Agreement for Expedited and Standard Process (Exhibit G)
      - Agreement Between the Company and the Company's Retail Customer (Exhibit H)
      - Landowner Consent Agreement (Exhibit I)
      - Schedule Z – Additional Information Required for Net Metering Service
  - 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 department to ISO-NE.
    - DER projects greater than 1 MW but less than 5 MW will require a notification by the Company's Customer Energy Integration department to ISO-NE via Attachment 4 under ISO-NE Planning Procedure (PP) 5-1.
    - DER projects greater than or equal to 5 MW will require a review of transmission system impacts and a Proposed Plan Application filed with ISO-NE. Refer to ISO-NE PP 5-1.
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 Massachusetts DPU, 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 system, then any previous information furnished by the Company to the Customer is subject to review and possible change, which may cause a delay in service.
8. The following website contains the Company's application of the MA SIDG net metering rules: [https://www.nationalgridus.com/masselectric/home/energyeff/4\\_net-mtr.asp](https://www.nationalgridus.com/masselectric/home/energyeff/4_net-mtr.asp).

## 5.4 Considerations During the Application Process for DER Interconnections in 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 Brockton, Lynn, and Worcester in Massachusetts, 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 Brockton, Lynn, and Worcester **should check the National Grid Website: "Area Network Maps"** [[http://www.nationalgridus.com/masselectric/business/energyeff/4\\_networkmap.asp](http://www.nationalgridus.com/masselectric/business/energyeff/4_networkmap.asp)]. **If that street location is highlighted in red (or near) the red line, then contact the Company at** Distributed.Generation@nationalgrid.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 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.
  1. 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. National Grid'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.
  2. 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 Institute of Electrical and Electronics Engineers (IEEE) Std. 1547.
  3. 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<sup>7</sup> 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 7-day duration based on nameplate generation rating, and

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<sup>7</sup> 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 Company's electricity tariff and MA SIDG.

- 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.

## 5.5 Interconnection Charges

Customer-Generators 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 electricity tariffs, M.D.P.U. 1320 and 1316 and the **MA SIDG**. 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, which are not intended to be all inclusive. Costs will be determined according to the Company's electricity tariff and the MA SIDG.

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

Item No.	Typical Company Support Activities Attributed to DER Customer's Project (Requiring Charges to the Customer)
1	Engineering acceptance review of DER 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 DER Customer installation to accepted design.
4	Field compliance verification - witness tests of DER 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 DER 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, 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 (analog 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 DER 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 DER Customer installation to accepted design.
9	Field compliance verification - witness tests of DER Customer protective devices coordinating with the Company Distribution EPS.

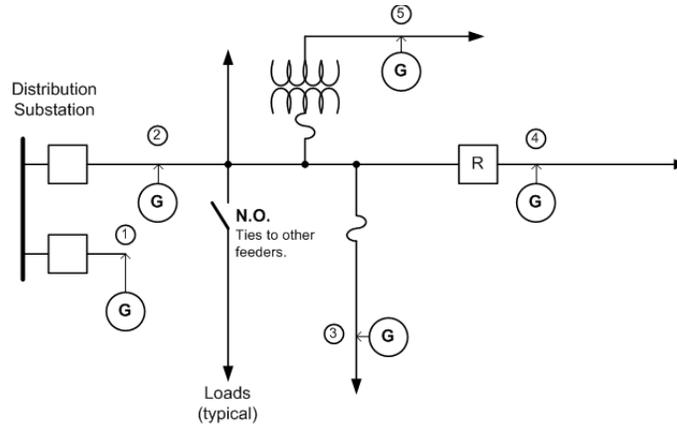
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Item No.	Typical Company Support Activities Attributed to DER Customer's Project (Requiring Charges to the Customer)
10	Project Management (CEI, Distr. Line, Distr. Station, etc.)

## 6.0 Potential Issues Related to Interconnection

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 utility 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 overvoltages
  - 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 systems to the Company EPS so that any negative impacts to the Company EPS performance can be avoided and without degradation of EPS safety and reliability. It is the intent of any Company study in accordance with SIDG 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, DER facilities connected to various locations on the radial distribution EPS (see Illustration 6.5-1) 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 6.5-1: Typical DER 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. Studies will be more complex and accommodating interconnections will likely require more involved infrastructure development, costs, and duration to construct.
    1. 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).
    2. 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.
  7. 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 electricity tariff, **M.D.P.U. 1316**. 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.<sup>8</sup>

<sup>8</sup> See Section 3 in the Company’s ESB750 for more information on multiple service requests.

## 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 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.

- For inverter based generation, this shall refer to the nameplate rating of the inverter(s). 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 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 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.

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 MA SIDG 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 parallel generators requires safeguards for synchronization and back feed situations in accordance with the **MA SIDG**. 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 **MA SIDG** for detailed requirements.

#### 7.1.1 Single Phase

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

- 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.

- Configured as a three-wire, line-to-line with neutral, or line-to-neutral with adequate load balance.
- A dedicated service lateral with a dedicated transformer, when required by the Company.

#### **7.1.2 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 shall not exceed 20 MW covered by the SIDG. For more than 20 MW, refer to ESB 756 Appendix A.

#### **7.1.3 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%.

#### **7.1.4 Neutral Stabilization, Ground Faults, and Grounding**

1. Where the Customer is served from a Company multi-grounded distribution circuit, an effectively grounded system with respect to the Company's EPS must be provided to ensure neutral stability and avoid distribution circuit over voltage during accidental isolation of the Company's area EPS from the main Company system. This may require an additional ground source. Adequate grounding can be provided either by the use of wye-delta main power transformer or by installing an appropriate grounding means (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 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:
  - 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).
  - 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-Generator's interconnection. Hence, it is required that the Customer-Generator 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-Generator to mitigate the increase in fault current.
  - If the Customer is permitted to interconnect through an un-grounded source, a "zero-sequence" voltage or "3V<sub>0</sub>" scheme will be required on the primary side of the approved delta primary wound transformer (see Figure 5) supplying the DER system.

3. As a minimum, the Customer's DER system equipment shall be grounded in accordance with the latest requirements of the National Electrical Code (NEC). For specific installations, refer to the applicable sections of this document and the Company's ESB 750.

## 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. Permanent Plaques: The Interconnecting Customer shall install and maintain clearly labeled permanent plaques in accordance with NFPA 70 (National Electrical Code) and MDPU 1320.
3. For large DER 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 752, 753, or 758 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 electricity tariff, M.D.P.U. 1331, describes qualifications for net 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<sup>9</sup> for parallel import connections 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. Customer-Generators 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.

## 7.3 Transformer

### 7.3.1 Secondary Served DER Customers

Where the Company provides secondary service, the Company's transformer is an equipment standard for service delivery voltages offered in M.D.P.U. 1316; see Section 3 in **ESB 750**. The maximum transformer size the Company will supply for a new secondary connected DER connection is 500 kVA where the non-DER premises electricity use is 500 kVA or less. 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-Generator's DER life cycle. If a dedicated transformer(s) is

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<sup>9</sup> "Detented metering" is measuring and registering power flow in a single direction by either mechanical, or electronic, or programming means in a revenue meter.

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 M.D.P.U. 1316 and as permitted by the **MA SIDG**.

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
2. Interconnection of DER to the customer side of the transformer creates undesirable effects on the Company's EPS.
3. 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.
4. 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-Generator to have primary service.

### **7.3.2 Primary and Higher Voltage Served DER 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.

#### **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.

The Company requires 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 it 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 a primary delta - 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 kW and above depending on DER saturation and other conditions on individual feeders.

Effective grounding may be accomplished with the following configurations:

1. A wye-grounded to wye-grounded transformer with a grounded generator source.
2. A wye-grounded connected primary winding with a fully insulated neutral and the secondary winding to have a delta connection. 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.
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.
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.

#### 7.3.2.2 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. Refer to Section 5.3.4 for specific grounding requirements.

## 7.4 Manual Generator Disconnecting Means

The Customer-Generator'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 need to be de-activated, however the Company reserves the right to operate the DER disconnect directly in emergency situations.

The Customer shall provide contact information for Customer personnel that can be reached 24/7, should complications arise with access to the Customer's equipment. Should there be any complications with Company access to the DER disconnecting means, the Company reserves the right to disconnect the Customer's service in its entirety via the next upstream Company owned disconnecting means.

The disconnecting means shall have the following characteristics:

1. According to the **MA SIDG**, 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).
2. **Rating:** Disconnecting means shall be rated to interrupt the maximum generator output; meet applicable Underwriters Laboratories (UL), American National Standards Institute (ANSI), and IEEE standards; and shall be installed to meet the NEC and all applicable local, state, and federal codes.
3. **Arrangement:** The connection of the disconnect switch shall have the line connection (i.e., jaw side) of the switch made to the utility source and 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 barriered from any live parts.
4. **Location and Type:**
  1. For those 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 ("knife 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. The Company shall exercise such right in accordance with Section 7.0 of MPDU 1320.
  2. For those 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 in the form of 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. The disconnecting means shall be installed between the DER system and the point of connection to the Customer's premises wiring system in accordance with the NEC. For installations above 600 V, the visual open of all three phases shall be capable of being observed without opening the equipment.
3. 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. 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.
  4. The location and type of disconnecting means for all DER projects will be reviewed on a case by case basis to confirm whether the Customer's proposed equipment is appropriate.
  5. **Access and Locks:** The disconnecting means must be readily accessible at all times to the Company to electrically isolate the Company's Distribution EPS from the Customer's generator facilities. In all instances, the disconnecting means shall have provisions to be locked in the open position with space for Company and Customer padlocks.
  6. **Maintenance:** The Customer is solely responsible for the maintenance of all fuses in fused, blade-type disconnect switches.
  7. **Identification:** All required disconnecting means shall be identified by a permanent sign as required by the NEC and the ESB 750.

## **7.5 Generator Interrupting Device Requirements**

### **7.5.1 General**

1. For any aggregate generation connected to a common feeder that is equal to or above 500 kW, an interconnection interrupting device such as a circuit breaker shall be installed at the Customer's site. The 500 kW criteria is 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 Utility 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-Generator 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. The Interconnection Customer is 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-Generator 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-Generator'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 MA SIDG. 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 **MA SIDG**. The Under Frequency relays for the all 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 **MA SIDG**.

The DER 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.

#### **7.6.1 Type Tested (Certified) Equipment**

Protective equipment that has been type tested and recognized under UL Standard 1741 by the **MA SIDG** for Group 1 DER facilities will be permitted. The Customer shall follow the testing requirements as outlined in the MA SIDG. **Exhibit 8** 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 MA SIDG 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<sup>10</sup> is subject to prior Company review and acceptance per section 7.6.3.2.

#### **7.6.3 Number of Relays Required**

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), is 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 initiate trip to the Company-designated generator interrupting device. Auxiliary relays, where used, shall be fail safe and utility grade.

##### **7.6.3.1 Certified Inverter-based Energy Resource Protection Requirements**

IEEE 1547 compliant and UL-1741 certified<sup>11</sup> 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 and its amendments ("IEEE 1547"). The amendment to the standard, IEEE 1547a, requires voltage and frequency ride through capabilities be available in all inverter based generation. The Customer-Generator shall provide the voltage and frequency ride through capabilities as specified in IEEE 1547a in any inverters installed as part of a DER facility proposed to interconnect to the Company's EPS. The voltage regulation and ride-thru capabilities shall be turned OFF unless otherwise required by the Company.

##### **7.6.3.1.1 Individual Certified Inverter-based Energy Resources below 500 kW**

If the inverter is IEEE 1547 compliant and UL-1741 listed, the internal relays are considered as the only required protection and an additional utility grade relay is not necessary 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 and voltage controlled overcurrent 51C.

##### **7.6.3.1.2 Individual Inverter-based Energy Resource Equal or above 500 kW**

IEEE 1547 compliant and UL-1741 listed inverter internal relay functions are considered as primary protection. The Company requires one additional utility grade relay to be

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<sup>10</sup> See definition of "utility grade" for protective device equipment in Section 4.

<sup>11</sup> See definition for "certified" in Section 4.

installed as secondary the utility grade protection for inverter-based solar PV generation equal or greater than 500 kW. The 27, 59, 81U/O, voltage controlled phase overcurrent 51C, and 51N or 51G elements shall be activated in the secondary utility grade protection relay. The Customer-Generator 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.

The utility grade relay failure alarm shall be wired to initiate trip to the Company-designated generator interrupting device. If two utility grade relays are used to provide the above functions, failure of either relay, or both, being out of service shall trip the interrupting device.

#### **7.6.3.2 All Non-Certified Parallel Generation**

##### **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 relaying and additional protective elements to be active in the utility grade relay(s).

##### **7.6.3.2.2 Energy Resources equal to or above 500 kW**

For any non-certified generator equal or above 500 kW, if the generator is equipped with internal relays with 27, 59, and 81U/O relays, one utility grade relay is required to be installed as the secondary protection. 27, 59, 81 U/O, and overcurrent elements for both phase and ground shall be active in the redundant relay. Otherwise, two utility grade relays and one Company-designated interrupting device shall be installed to meet the protection requirements. 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.

#### **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.

##### **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.

#### **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.

- **AC Inputs:** Each relay shall have its own AC test switch. DC inputs or outputs are not permitted on AC test switches.
- **DC Inputs and Outputs:**
  - 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-Generator'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 requirements including capability for under 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 requirements including capability for under frequency ride through. The under-frequency trip setting shall not be higher than 58.9 Hz, as to not conflict with the under-frequency load shedding schemes on the Company's EPS. For adjustable under frequency settings in table 2 of IEEE 1547, the chosen setting shall not fall within the prohibited region of NERC PRC-024-2. See Table 7.6.12.1-1 below for default frequency relay settings.

#### **7.6.9 Synchronizing Devices**

The DER 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 Relay Devices

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. For inverter-based systems, a voltage controlled phase element (51C) is required. These relays shall utilize voltage sensing via the Yg-Yg VTs specified in section 7.6.4.2.

### 7.6.11 Utility Grade Protective Device Settings and Verification

#### 7.6.11.1 Default Voltage and Frequency Set points for all types of 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 Parallel Generation Default Voltage & Frequency Set Points**

DEVICE	PICKUP RANGE	TIME DELAY RANGE (sec)	DEFAULT TIME DELAY (sec)
Under Frequency (81U)	$\leq 56.5$ Hz	0.16	0.16
Under Frequency (81U)	$< (58.9 - 57.1)$ Hz adjustable Default set to 58.5 Hz	0.1 – 300.0	300
Over Frequency (81O)	$61 \text{ Hz} \leq f < 62.0$ Hz	0.1 – 300.0	300
Over Frequency (81O)	$> 62.0$ Hz	0.16	0.16
Under Voltage (27)	$< 50\%$ of Nominal	0.1 – 11.0	0.16
Under Voltage (27)	$50\% \leq V < 88\%$ of Nominal	0.1 – 21.0	2
Over Voltage (59)	$110\% < V < 120\%$ of Nominal	0.1 – 13.0	1
Over Voltage (59)	$\geq 120\%$ of Nominal	0.16	0.16

Settings other than the default 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.

#### 7.6.11.2 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 (kW)	Max. Frequency Difference ( $\Delta f$ , Hz)	Max. Voltage Difference ( $\Delta V$ , %)	Max. Phase Angle Difference ( $\Delta \Phi$ , degrees)
0-500	0.3	10	20
>500 – 1,500	0.2	5	15
>1,500 – 10,000	0.1	3	10

#### 7.6.11.3 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.

#### 7.6.11.4 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:

- control wiring verified against the accepted design drawings, and,
- the calibration test performed satisfactorily according to the relay setting document of the accepted design.

The Company reserves the right to witness the Customer's functional test of the required devices, i.e., trip tests. The Customer-Generator shall submit a witness test plan to the Company for review at least 4 weeks prior to the scheduled witness test. If needed, consult the Company for guidance on preparing a witness test plan. This activity will normally be performed on a schedule as specified by Section 4.2.4 in the **MA SIDG**.

The Customer shall be responsible to specify the settings, calibrate, test, and maintain the balance of their equipment.

#### 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-Generator may propose alternative methods of anti-islanding protection of their own generation facility, although it is the Customer-Generator'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 National Grid 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 voltage or provide Var support functions. Any inverter type generation established as voltage regulating or Var supportive will be reviewed under section 7.6.12.4 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  $\leq 33\%$  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 National Grid'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
  - a. DER  $\geq 300$  kW and DER  $> 33\%$  minimum load and is connected to  $< 5$  kV EPS.
  - b. DER 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<sup>12</sup>
  - a. If line faults (phase and ground where applicable) cannot be cleared by DER protective device or the Company's PCC recloser.<sup>13</sup>
  - 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-Generator'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 Certified DER<sup>14</sup>

1. All inverters shall have an 88% voltage trip within 2 seconds to be considered in this section.
2. Proposed DER rated  $\leq 50$  kW

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<sup>12</sup> While the intent of this unintentional islanding protection policy is to encourage DER installations while minimizing inhibitive impacts to the DER installation, National Grid reserves the right and flexibility to enforce protective measures deemed required for the safety and reliability of the EPS.

<sup>13</sup> Customers should be aware that  $>15$ kV 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).

<sup>14</sup> Inverter firmware derating is not acceptable for reduction of system size to satisfy thresholds within this document.

- a. No requirements.
3. Proposed DER rated  $> 50$  kW and  $< 1000$  kW
  - a. Line section aggregated non-certified DER is  $\leq 10\%$  of mix.
    - i. No additional requirements.
  - b. Line section aggregated non-certified DER is  $> 10\%$  and  $\leq 25\%$  of aggregate DER.
    - i. Sandia screening<sup>15</sup> may be applicable depending on inverter models on segment.
    - ii. Company-owned PCC recloser and reclose blocking required if Sandia screens not passed.
      1. Detailed risk of islanding (ROI) study may be performed at the Customer-Generator's request. If results of the detailed study show no significant risk of islanding for a period greater than 2 seconds, then the recloser and reclose blocking is waived.
  - c. Line section aggregated non-certified DER is  $> 25\%$  of all DER.
    - i. NG PCC recloser and reclose blocking required<sup>16</sup>
      1. Detailed ROI study may be performed at the Customer-Generator's request. If results of the detailed study show no significant risk of islanding for a period greater than 2 seconds, then reclose blocking is waived. Company-owned PCC recloser is waived for aggregate DER  $\leq 67\%$  of line load to generation ratio or  $< 500$  kW.
4. Proposed DER rated DER  $\geq 1000$  kW
  - a. Company-owned PCC Recloser required.
  - b. Reclose blocking required if line segment aggregate DER  $> 50\%$  of minimum load.

#### **7.6.12.4 Non-certified & voltage regulating inverters, induction & synchronous machines**

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

### **7.7 Monitoring and Control (M&C) at DER Facility**

DER ranging from 250 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 (EMS) and to incorporate the ability for the Company's system operators via EMS 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.

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<sup>15</sup> The Sandia screens (<http://energy.sandia.gov/wp-content/gallery/uploads/SAND2012-1365-v2.pdf>) are valid only for those certified inverters that have been confirmed, in writing from the manufacturer, to meet the definition of the Sandia Frequency Shift (SFS), or Sandia Voltage Shift (SVS) as positive feedback based methods according to the report or for inverters using impedance detection with positive feedback. SFS and SVS both rely on positive feedback to work.

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

<sup>16</sup> Where feasible, installing a PCC recloser in front of the non-certified DER may reduce or eliminate any further requirements to the subject applicant DER.

**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. Where available, the company will utilize the Company-owned PCC Recloser serving the DER installation to obtain Company’s operational polling data.
3. 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.
4. The company reserves the right to require the IPP customer to install a RTU at their facility for any special circumstances. One situation where an EMS-RTU may be required is where there is Distribution EPS feeder selectivity operation.

**7.7.2 For Non IPP - “Behind the meter” projects (DER’s 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
5kV or below.	500 kW or greater
greater than 5kV but less than 15kV	1 MW or greater
>15kV	1.8 MW or greater

2. EMS-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 EMS-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-Generator’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 EMS 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 EMS-RTU point list for inputs required at the DER system.*

5. When a Company EMS-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-Generator 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.

## 7.8 Voltage and Frequency Control

1. Inverter based generators shall be in compliance with all revisions of IEEE 1547. The amendment to the standard, IEEE 1547a, requires voltage and frequency ride through capabilities be available in all inverter based generation. The Customer shall provide the voltage and frequency ride through capabilities specified by IEEE 1547a in any inverters installed as part of a generator proposed to interconnect on the Company EPS.
2. These capabilities shall be disabled by default unless otherwise approved by the Company.

## 8.0 Testing and Commissioning

1. The Company reserves the right to witness the Customer-Generator's functional testing of the required devices.
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-Generator 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.
5. All required equipment test reports shall be submitted per ESB 751 prior to final TCP acceptance.
6. 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 MA-SIDG between 0.90 leading or lagging (VAR or voltage support can also be considered within machine ratings). 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-Generator 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. The Customer-Generator 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-Generator operating and maintenance responsibilities.
4. The Customer's service and backup service requirements from the Company's system shall be requested using the prescribed forms in the Company's electricity tariff, M.D.P.U. 1316.
5. Where the Company is requested to supply demand pulse information (either analog or digital), its use is not intended for generator dispatch or control.
6. 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.

## 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 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, M.D.P.U. 1316 and the limits and cost responsibilities specified in the :

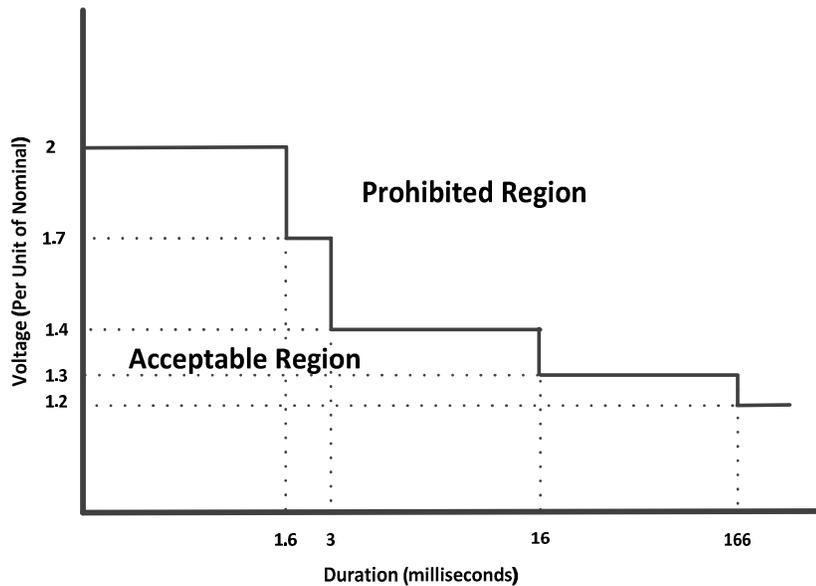
- Check service point voltage for any discernible voltage fluctuation.
- Check service point frequency for any discernible frequency fluctuation.
- Check PCC power factor to ensure it is no less than 90% (leading or lagging).
- Check service point harmonic distortion to ensure limits specified in ESB 750 and the MA SIDG 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 power quality in accordance with the Company's electricity tariff, M.D.P.U. 1316.
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 adhere to the Transient Over-voltage Tolerance curve as defined in Figure 10.3-1.



**Figure 10.3-1: Transient/Temporary Overvoltage Tolerance Curve**

IEEE 1547 settings require that an inverter-based DER ceases to energize the EPS in 160ms (10 cycles) for an overvoltage of 1.2 per unit (pu) or greater of nominal voltage. This trip point is inadequate to prevent damage to utility and customer equipment depending on the magnitude of the overvoltage per Figure 10.3-1 above. These issues could affect the inverter-based DER facility, as well as affect utility and other customer equipment on the feeder.

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 acceptable 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 Figure 10.3-1. The letter shall be on the manufacturer’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 Interconnection 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 **MA SIDG**, 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<sup>17</sup> 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.

<sup>17</sup> Refer to Section 5.6.4 regarding technical requirements for disconnecting means-out breakers over 600V and the Company’s electricity tariff, M.D.P.U. 1316 for limitations of service.

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- 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 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 **MA SIDG** 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.
- 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

<u>Version</u>	<u>Date</u>	<u>Description of Revision</u>
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	05/11/12	Revised and formatted incorporating tech requirements of MA DPU 1219 Dec. 2009.
3.0	07/15/15	Revise entire document for MA DPU 1219 May 2013 MA DPU 1320 June 2015 and technical updates.
4.0	08/03/17	June 2017 revise for MDPU 1320 October 2016, IEEE 1547a amendment, and technical updates.

## 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	MA SIDG § or ESB ref.
<b>Project Definition &amp; Conceptual Analysis Phase</b>		
1	Customer M.D.P.U. 1320 Exhibit B Expedited/Standard Interconnection Application Form w/technical submittal & prelim. design received	3.3 or 3.4, Figure 1, Table 1
2	Company Preliminary Technical Assessment & cost estimate for Impact or Detailed Study	3.0, Table 2
3	Company M.D.P.U. 1320 Exhibit F or G Retail Connection Agreement executed with Customer	Exhibit F or G
4	Customer commits to Impact or Detailed Study and provides advance payment	5.0
<b>Final Design Review Phase</b>		
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
<b>Installation Progress Review Phase</b>		
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
<b>Installation Compliance Verification Phase</b>		
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
<b>Energization &amp; Synchronization Phase</b>		
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	3.2 or 3.3, ESB 755

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ID	Activity Description	MA SIDG § or ESB ref.
	interconnections >600V)	
23	Company proceeds with energization	
24	Customer is permitted to synchronize generation facility in parallel to the Company's supply	
<b>Project Closeout Phase</b>		
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 National Grid Massachusetts Secondary Network EPS Areas**

### **Bay State North/West Division**

Lynn:

[http://www.nationalgridus.com/masselectric/non\\_html/Lynn\\_Network\\_Feeder\\_Final\\_08-17-12.pdf](http://www.nationalgridus.com/masselectric/non_html/Lynn_Network_Feeder_Final_08-17-12.pdf)

Worcester:

[http://www.nationalgridus.com/masselectric/non\\_html/Worcester\\_Network\\_Feeder\\_Final\\_08-17-12.pdf](http://www.nationalgridus.com/masselectric/non_html/Worcester_Network_Feeder_Final_08-17-12.pdf)

### **Bay State South Division**

Brockton:

[http://www.nationalgridus.com/masselectric/non\\_html/Brockton\\_Network\\_Feeder\\_Final\\_09-12-12.pdf](http://www.nationalgridus.com/masselectric/non_html/Brockton_Network_Feeder_Final_09-12-12.pdf)

National Grid customers in the downtown districts of Brockton, Lynn, and Worcester **should check the [National Grid Website under: "Area Network Maps"](http://www.nationalgridus.com/masselectric/business/energyeff/4_networkmap.asp)** [[http://www.nationalgridus.com/masselectric/business/energyeff/4\\_networkmap.asp](http://www.nationalgridus.com/masselectric/business/energyeff/4_networkmap.asp)]. **If that street location is highlighted (or near) the red line, contact the Company's DGES department via E-mail addressed to [Distributed.Generation@nationalgrid.com](mailto:Distributed.Generation@nationalgrid.com) to determine if the proposed location is served in National Grid's Secondary Network area.**

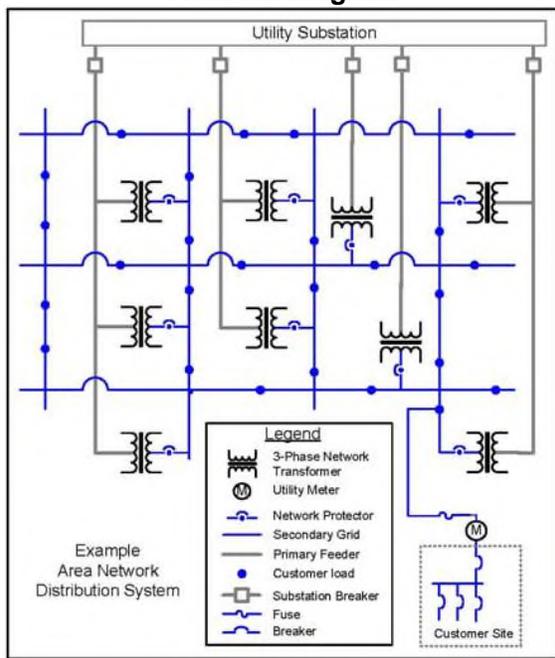
## EXHIBIT 3: Distribution Secondary Grid and Spot Network Description

In Massachusetts, National Grid 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 Brockton, Lynn, and Worcester in Massachusetts 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.

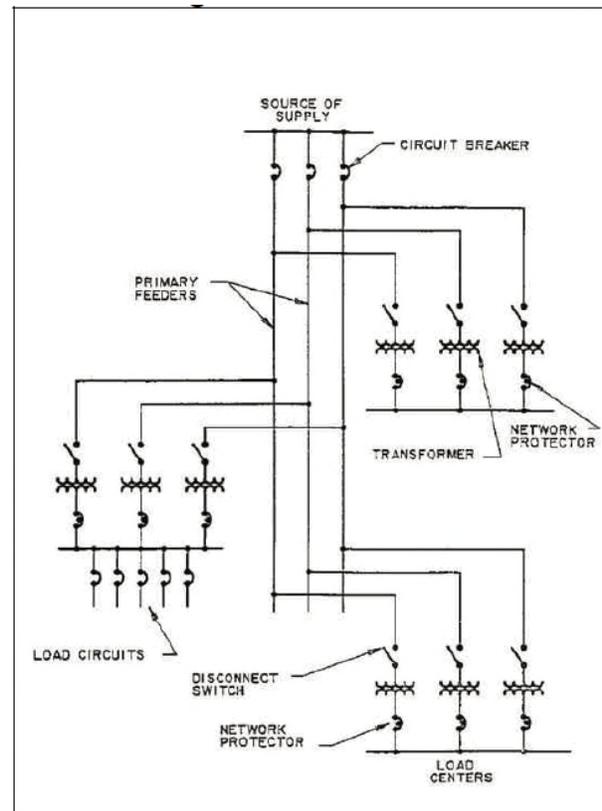
In distribution secondary network systems, devices called "network protectors" are usually arranged to automatically connect its associated transformer to the network system when conditions are such that the transformer when connected will supply power to the network and to automatically disconnect the 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 Grid 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 Spot Network Diagram**



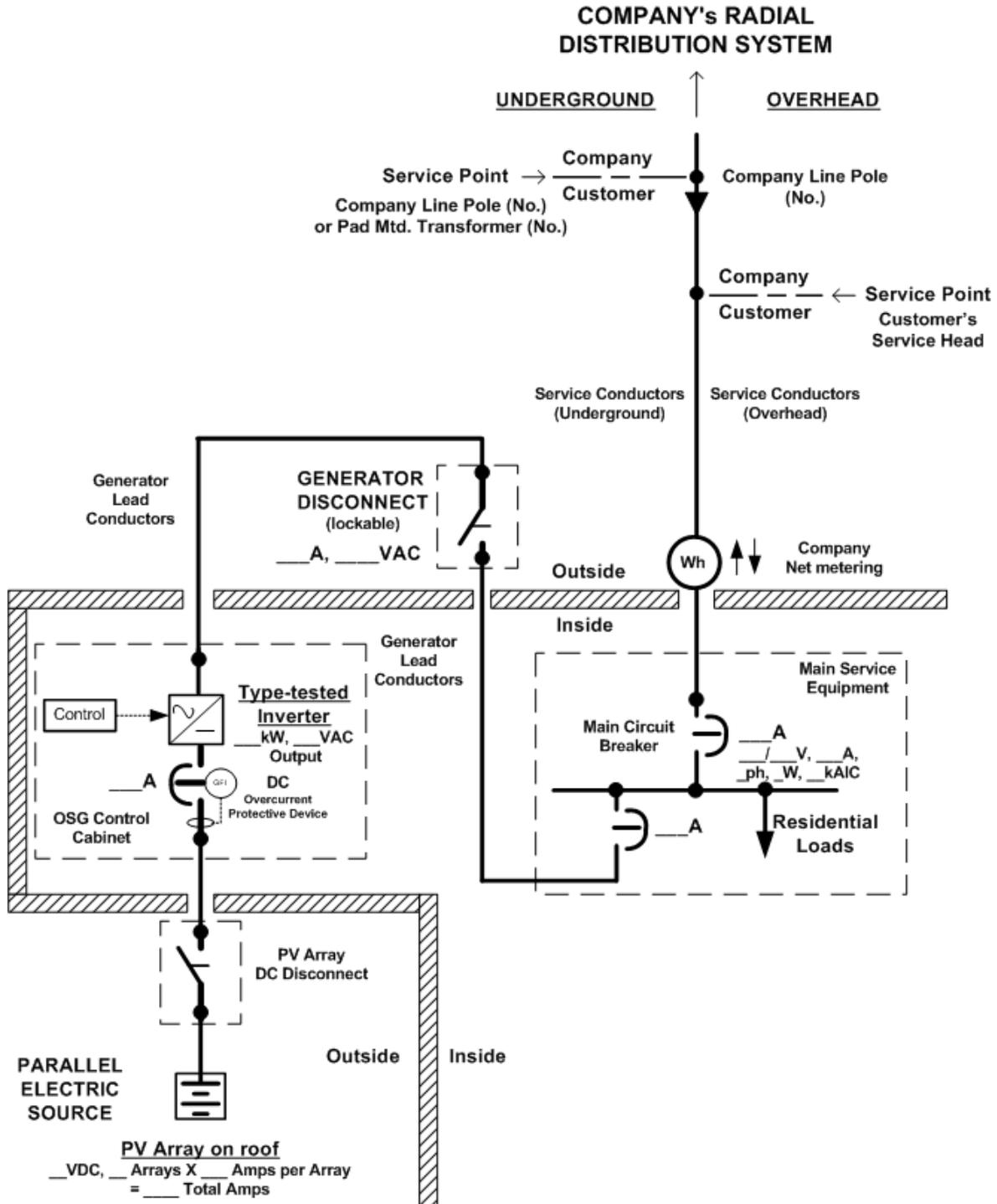
Spot networks are similar to grid (area) networks except they serve a single premise.

## **EXHIBIT 4: Recommended Guidelines for Residential and Commercial Single-line Diagram Submittals**

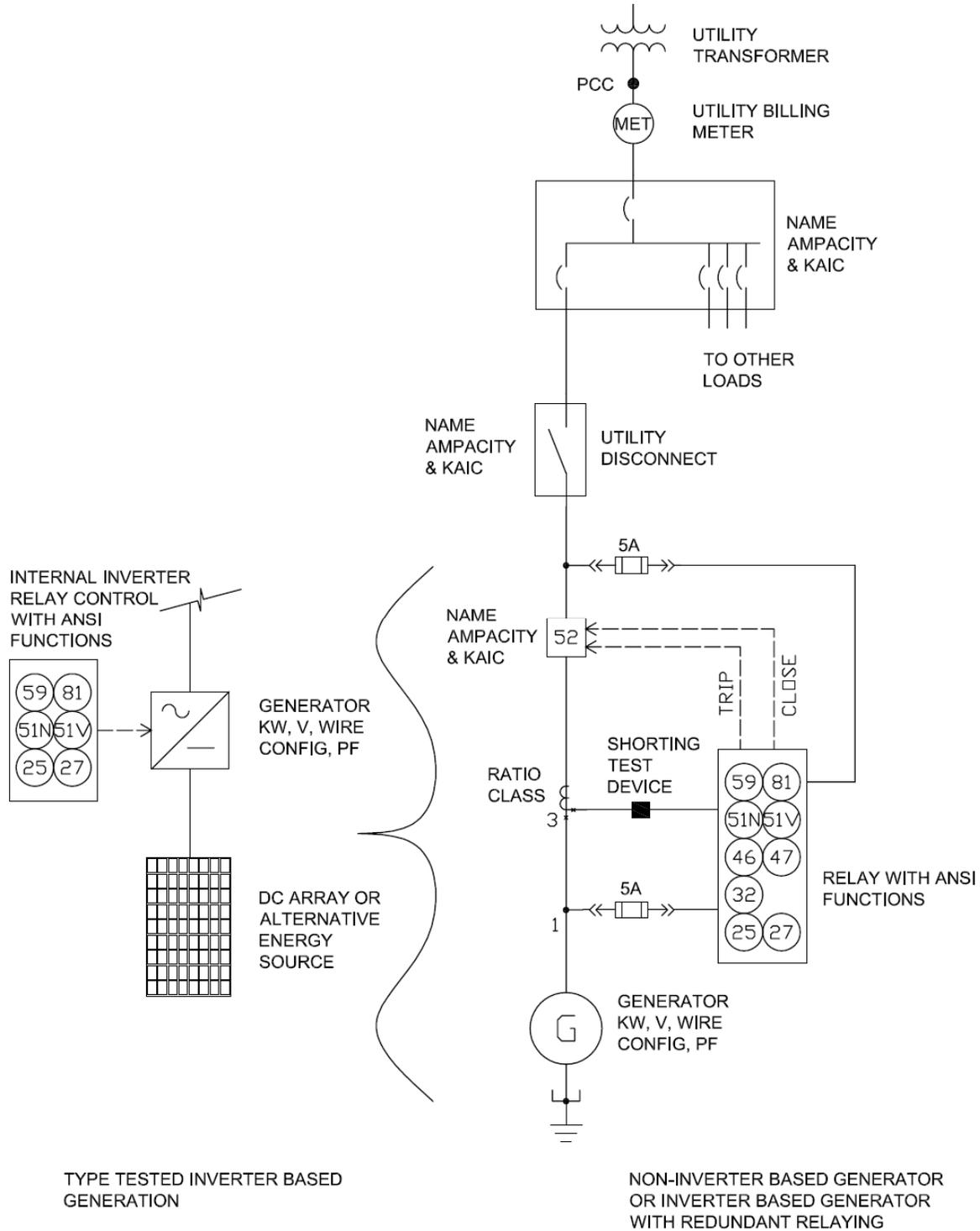
Refer to **Figures 2 and 3** for typical illustration and symbology.

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.
11. Show connections and ratings of power transformer windings for any to be used.
12. Identify Generator Disconnect and its ratings, the service point, and the PCC.
13. 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-Generator. 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 Symbolology for Electrical Drawings**

ELEMENTARY SWITCH DEVICES								CONTACTS AND RELAYS	
FLOW		PRESSURE		LIQUID LEVEL		TEMPERATURE		CONTACTS	
CLOSED RISING	OPENS RISING	CLOSED RISING	OPENS RISING	CLOSED RISING	OPENS RISING	CLOSED RISING	OPENS RISING	NORMALLY OPEN OR "a" CONTACT	NORMALLY CLOSED OR "b" CONTACT
LIMIT				PUSHBUTTON		RELAY COIL			
NORMALLY OPEN	NORMALLY OPEN - HELD CLOSED	NORMALLY CLOSED	NORMALLY CLOSED - HELD OPEN	NORMALLY OPEN	NORMALLY CLOSED				
ELEMENTARY FUSE DEVICES			BATTERY OR DC SOURCE			CONNECTIONS			
FUSE	SOLID LINK	IN REMOVABLE CARTRIDGE OR PULL BLOCK	GENERAL OR SINGLE CELL	MULTI CELL (COMMON)	GROUND	SHORT CIRCUIT (3-PHASE CONNECTION)	SEPARABLE CONNECTORS OR DRAW OUT FEATURE		
DISCONNECTS (UNDER 600 V)		CIRCUIT BREAKERS			TRANSFER SWITCH				
NON-FUSED DISCONNECT	FUSED DISCONNECT	GENERIC OR AIR TYPE	CB OR INTERRUPTING DEVICE (OTHER THAN AIR)		TWO POSITION	THREE POSITION			
CAPACITOR	ANTENNA	THERMAL OVERLOAD	INDICATING LIGHT * = LENS COLOR:						
			A - AMBER B - BLUE C - CLEAR G - GREEN O - ORANGE P - PURPLE R - RED W - WHITE Y - YELLOW						
TRANSFORMERS AND INSTRUMENT TRANSFORMERS									
3-PHASE, WYE		3-PHASE, DELTA					3-PHASE ZIGZAG		
GROUNDING NEUTRAL	UNGROUNDING	DELTA	CORNER GROUNDING	OPEN DELTA	OPEN DELTA CORNER GROUNDING	BROKEN DELTA	UNGROUNDING	GROUNDING	
GENERIC TWO WINDING TRANSFORMER	GENERIC THREE WINDING TRANSFORMER, TERTIARY TYPE		EXTERNAL TO BUSHING	BUSHING MOUNTED					
			■ OR • OR ×						
			CURRENT TRANS. WITH POLARITY MARKS SHOWN		FUSED POTENTIAL TRANSFORMER				

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

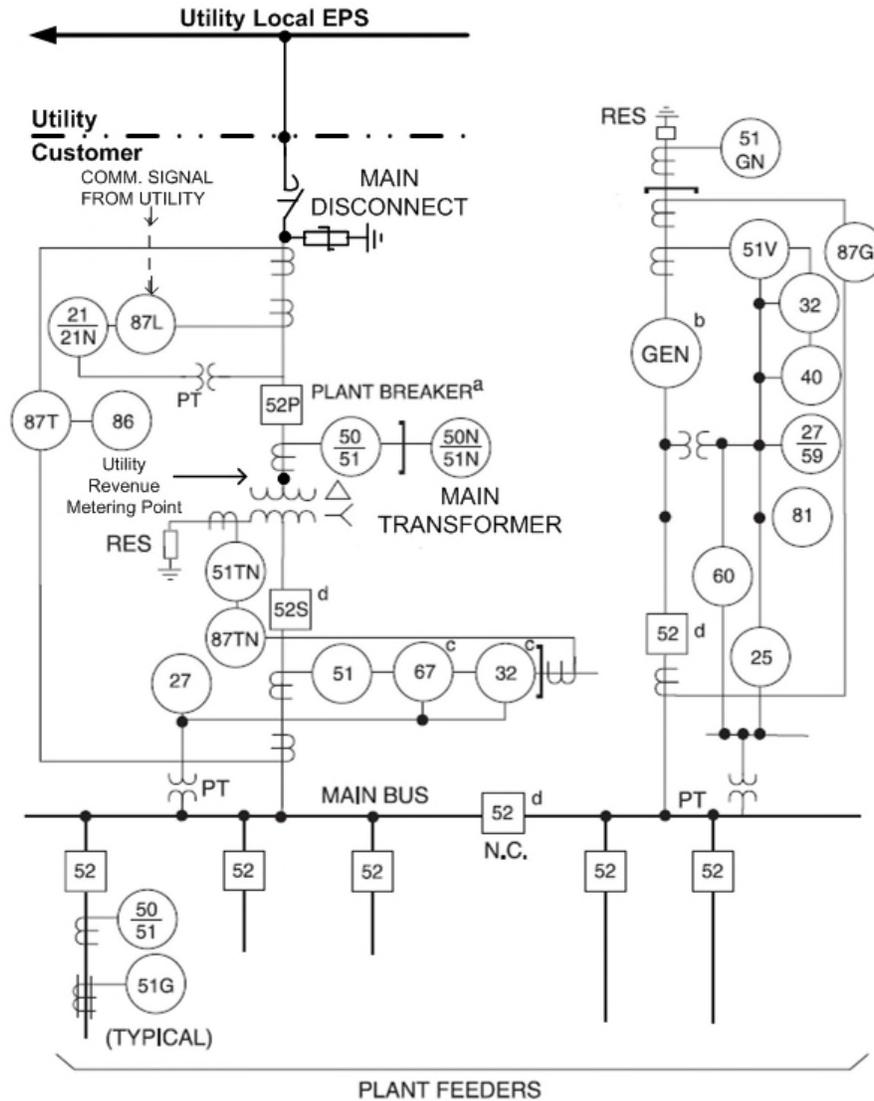
Refer to Figures 1 and 2 for typical illustrations.

In addition to Exhibit 4:

14. 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**):

<b><u>Device Number</u></b>	<b><u>Function</u></b>
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 interrupter 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.

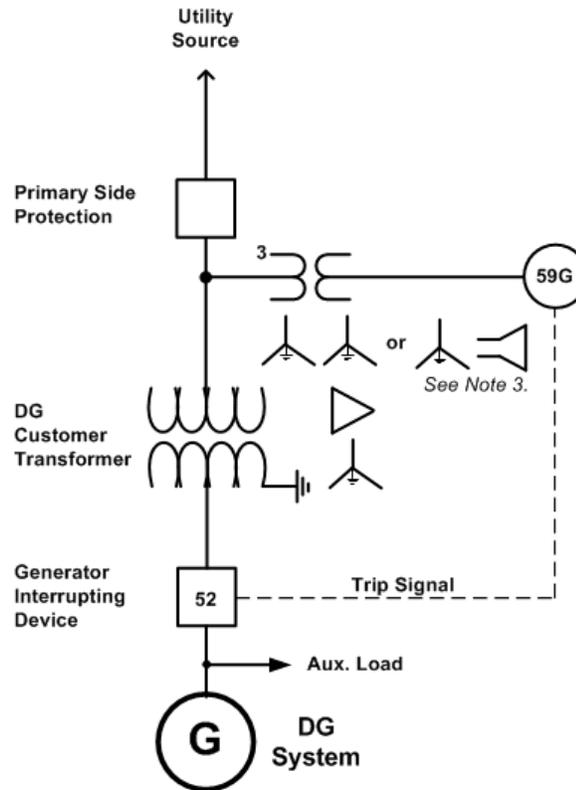
[TYPICAL ONLY]

## 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.

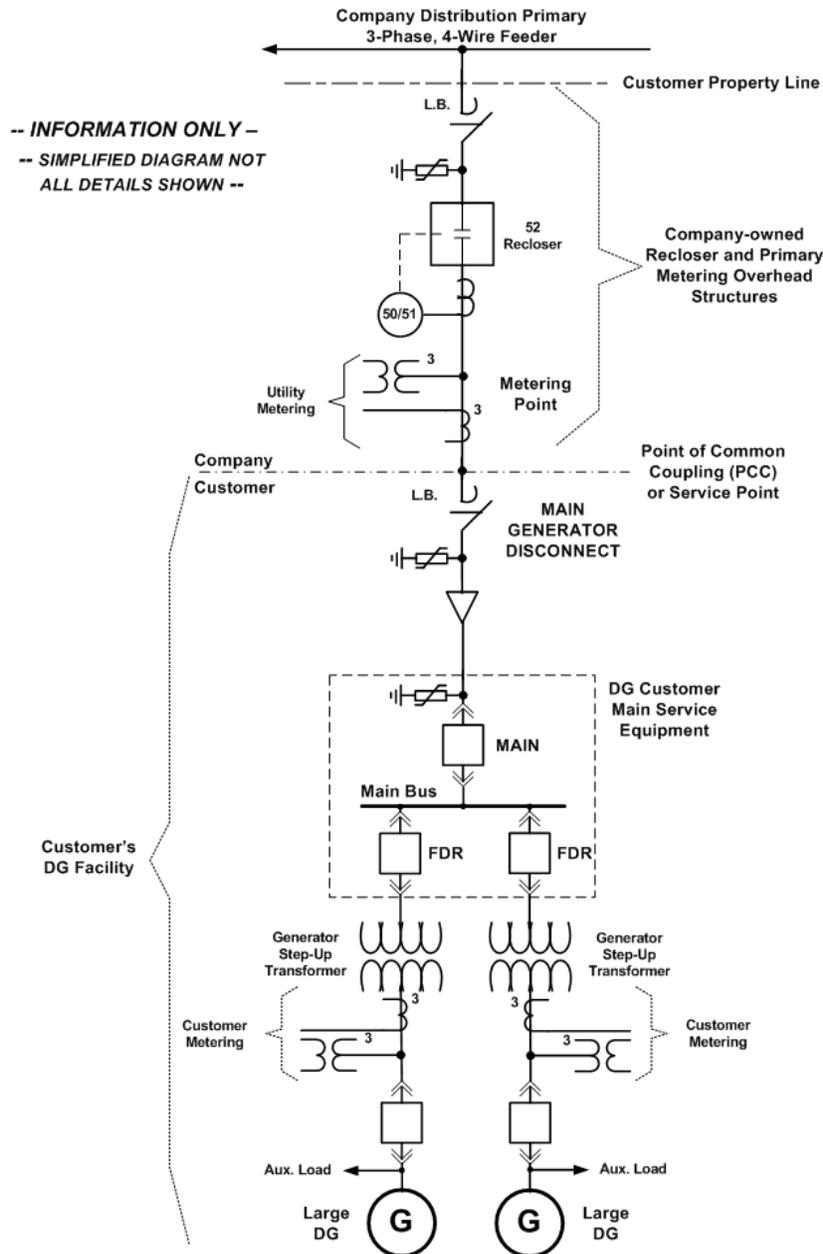


-- INFORMATION ONLY --  
-- SIMPLIFIED DIAGRAM NOT ALL DETAILS SHOWN --

## EXHIBIT 6: Typical Overhead Primary Service Configuration for Large DER Installations

The DER 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 DER Customer.

All Company-owned service lateral facilities and equipment on private property will require easements. These easements will be the responsibility of the DER 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)

# **Electric System Bulletin No. 756 Appendix D:**

## **Distributed Generation Connected to National Grid Distribution Facilities per the Rhode Island Standards for Connecting Distributed Generation**

**June 2017 Version 3.0**

ESB 756 Appendix D is part of the ESB 750 series

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### 1.0 Purpose

1. Electric System Bulletin (ESB) 756 Appendix D covers requirements for interconnecting customers proposing to install a distributed energy resource (DER) system (“Interconnecting Customer” or “Customer” or “Customer-Generator”) to National Grid’s (“the Company”) Rhode Island electric power system (EPS) for State jurisdictional projects.
2. ESB 756 Appendix D does not cover the technical federal and state transmission operator jurisdictional requirements (ISO-NE and 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.<sup>1</sup>
3. This ESB supplements **ESB 750** and the **RI SCDG** and 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 SCDG does not apply to DER units larger than 10 MW. 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.
4. ESB 756 and this Appendix D are available from the Company’s website at <http://www.nationalgridus.com/electricalspecifications> and in printed form by contacting either of the Call Centers in Massachusetts or New York (see inside cover of ESB 750 for Customer Service Center telephone numbers). However, since printed copies may not reflect the latest updates, please refer to the Company’s website for the latest authorized versions.

### 2.0 Scope

1. This Appendix D to ESB 756 is provided to assist a Customer-Generator desiring to interconnect a generator facility to National Grid’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 covered by the RI SCDG connected to the Company EPS that are net metered generation sources (Net Metered Classes) or non-net metered generation sources including other distributed energy resources (DER) such as energy storage systems (ESS), facility or campus-style microgrids, and where DER owners, or DER owners as clients of registered aggregators, sign onto a 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 also apply. Where conflicts arise, the technical provisions of ESB 756 Appendix D take precedence.

---

<sup>1</sup> 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](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.

National Grid / Supplement to Specifications for Electrical Installations / ESB 756D-2017 ver. 3.0

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 NEC and the Company's ESB 750 for more information.

4. For the RI State jurisdictional requirements of the RI SCDG, please refer to the retail tariff requirements at the following Company website:  
RI: [http://www9.nationalgridus.com/narragansett/business/energyeff/4\\_interconnection-process.asp](http://www9.nationalgridus.com/narragansett/business/energyeff/4_interconnection-process.asp)
5. 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 systems, 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 standards applicable to this bulletin include, but are not limited to:
  - Institute of Electrical and Electronics Engineers (IEEE) Std. 1547 "Standard for Distributed Resources Interconnected with Electric Power Systems"
  - Underwriters Laboratories (UL) Std. 1741 "Inverters, Converters and Charge Controllers for Use in Independent Power Systems"
  - 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.

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- 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 their proposed site.
3. The Customer shall comply with 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<sup>2</sup>
  - **ESB 752** - Service Above 15,000 volts
  - **ESB 754** - Outdoor Pad Mounted or Vault Enclosed Single and Three Phase Transformer
  - **ESB 755** - Operation & Maintenance Requirements for Services Above 600 Volts
  - **ESB 758** - Primary Service to Metal Enclosed Gear
  - **R.I.P.U.C. 2163** - The Narragansett Electric Company Standards for Connecting Distributed Generation (RI SCDG)
  - **R.I.P.U.C. 2130** - The Narragansett Electric Company Terms and Conditions for Distribution Service
  - **R.I.P.U.C. 2178** - The Narragansett Electric Company Net Metering Provision
  - **R.I.P.U.C. 2151-C** – The Narragansett Electric Company Renewable Energy Growth for Residential Customers
  - **R.I.P.U.C. 2152-C** - The Narragansett Electric Company Renewable Energy Growth for Non-Residential Customers
  - **R.I.P.U.C. 2098** – 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@nationalgrid.com](mailto:Distributed.Generation@nationalgrid.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.

1. **Certified:** Equipment that is approved by examination for safety; see NEC Articles 90 and 110.
2. **Certified DER:** A UL 1741 certified inverter.
3. **Generator:** Equipment that produces power.
4. **Generator Set** or **Genset:** The singular assembly of an electrical generator and a prime mover.
5. **Line section:** Any EPS circuit segment that can be isolated via an automatic interrupting device such as a sectionalizer, recloser, or circuit breaker.
6. **Non-certified DER:** Any non-UL 1741 inverter, induction or synchronous DER.
7. **Prime Mover:** The mechanical 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.
8. **Recloser:** A line protective device having automatic interruption and controlled reclosing characteristics.

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<sup>2</sup> ESB 751 Applies regardless of service voltage for Distributed Energy Resources (DER).

9. **Utility Grade:** Refers to protective device equipment complying with ANSI/IEEE C37.90, ANSI/IEEE C37.90.1 and ANSI/IEEE C37.90.2.
10. **Interconnection Customer and Customer-Generator** are used synonymously in this document.

## 5.0 Customer-Generator 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. 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 10MW 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 RI SCDG contained in National Grid's Rhode Island and Narragansett Electric Tariff, R.I.P.U.C. 2163 ([https://www9.nationalgridus.com/non\\_html/RI\\_DG\\_Interconnection\\_Tariff.pdf](https://www9.nationalgridus.com/non_html/RI_DG_Interconnection_Tariff.pdf)).

#### 5.1.1 DER Applicant Technical Data Submission

The Customer shall submit, at the time of application, all relevant documentation as indicated in R.I.P.U.C. 2163. The Company reserves the right to request additional information as needed specific to the interconnection of Customer-Generator equipment including, but not limited to, three line diagrams, control diagrams, equipment test reports and other information; see the Company's ESB 751.

##### 5.1.1.1 Control Diagrams

The Customer-Generator 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.

##### 5.1.1.2 Interconnection Facility Equipment Data Sheets

The Customer-Generator 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.

##### 5.1.1.3 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. Interfacing transformer
2. Interrupting devices
3. Isolation device(s) (e.g. Generator Disconnect)
4. Point of Common Coupling (PCC)
5. Company pole number nearest the proposed PCC
6. Company line extension to site and from nearest Point of Interconnection
7. Restricted accesses, fences, gates and access controls
8. 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.
9. Generator location
10. Existing service(s)

Site plans shall be to scale with approximate distances indicated. In addition to site plan, the Company may request an assessor map to determine property lines, wetlands and easements.

#### **5.1.1.4 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:

- Method of ESS connection whether: (1) ESS directly connected to utility EPS; (2) DER and ESS DC coupled; (3) DER 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.
- Sequence of operation for the ESS' charging and discharging capabilities and the maximum ramp rate in Watts/minute.
- Non-UL 1741 listed inverters will require a utility intertie relay with the appropriate IEEE 1547 functions, settings, and islanding protection according to the Company's [ESB 756](#) jurisdictional requirements.
- Service configuration and revenue metering provisions shall meet the Company's [ESB 750](#) and its applicable supplements.

#### **5.1.1.5 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. Facility or campus-style microgrid applications have certain characteristics described here, all of which fall under the U.S. Department of Energy (DOE) definition.<sup>3</sup> 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.

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<sup>3</sup> *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."*

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.<sup>4</sup>

## 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 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 a part of the Company EPS and where the Customer and the Company have a mutual interest the interconnection is required to preserve the safety, reliability, security, power quality, and operational efficiency needs of the Company 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 is determined, where such purpose can be either:
  - peak shaving,<sup>5</sup>
  - net energy metering for solar, wind, or agricultural projects as under the Company's net-metering tariff, RIPUC 2178, or
  - export energy for a QF with an agreement for sales<sup>6</sup> according to the Company's tariff provisions.
  - Renewable Energy Growth (RE Growth Program) according to RIPUC 2152-C (for Non-Residential Customers), or RIPUC 2151-C (for Residential Customers).
3. For new electric service or modifications to electric service to accommodate the Customer's parallel generator, 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,
  - a. 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.

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<sup>4</sup> See *NFPA 70-2017 National Electrical Code®* for installation requirements of premises wiring systems related to microgrids.

<sup>5</sup> *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.*

<sup>6</sup> *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.*

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- b. 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. 2163 Exhibit A or B application is submitted to the Company's Distributed Generation Services 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. 2163 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. 2163  
[https://www9.nationalgridus.com/non\\_html/RI\\_DG\\_Interconnection\\_Tariff.pdf](https://www9.nationalgridus.com/non_html/RI_DG_Interconnection_Tariff.pdf) ),
  - The Company's Distributed Generation Services **electronic mail address** as follows for inquiries: [Distributed.Generation@nationalgrid.com](mailto:Distributed.Generation@nationalgrid.com), and
  - The Company's ([www.nationalgridus.com](http://www.nationalgridus.com)) "Distributed Generation" web site at [http://www.nationalgridus.com/narragansett/home/energyeff/4\\_interconnect.asp](http://www.nationalgridus.com/narragansett/home/energyeff/4_interconnect.asp) for information and forms listed below (from R.I.P.U.C. 2163 [https://www9.nationalgridus.com/non\\_html/RI\\_DG\\_Interconnection\\_Tariff.pdf](https://www9.nationalgridus.com/non_html/RI_DG_Interconnection_Tariff.pdf)) 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 (ISR DG) 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 will require a review of transmission system impacts and a Proposed Plan Application filed with ISO-NE. Refer to ISO-NE PP 5-1.
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: [http://www.nationalgridus.com/narragansett/home/energyeff/4\\_net-mtr.asp](http://www.nationalgridus.com/narragansett/home/energyeff/4_net-mtr.asp).

#### 5.4 Considerations During the Application Process for DER Interconnections in the 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 National Grid Website: "Area Network Maps"** [[https://www9.nationalgridus.com/narragansett/home/energyeff/network/5\\_area\\_networkmaps.asp](https://www9.nationalgridus.com/narragansett/home/energyeff/network/5_area_networkmaps.asp)]. **If that street location is highlighted in red (or near) the red line, then contact the Company at ([Distributed.Generation@nationalgrid.com](mailto:Distributed.Generation@nationalgrid.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.
  1. 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. National Grid'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.
  2. 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 Institute of Electrical and Electronics Engineers (IEEE) Std. 1547.
  3. 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<sup>7</sup> 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 7-day duration based on nameplate generation rating, and

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<sup>7</sup> 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 Company's electric tariff and RISCDG.

- 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.

## 5.5 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 electric tariffs, R.I.P.U.C. 2163 and 2130 and the **RI SCDG**. 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 DER Customer’s Project Requiring Charges to the Customer)
1	Engineering acceptance review of DER 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 DER Customer installation to accepted design.
4	Field compliance verification - witness tests of DER 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 DER 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, 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 DER 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 DER Customer installation to accepted design.
9	Field compliance verification - witness tests of DER Customer protective devices coordinating with the Company Distribution EPS.
10	Project Management (CEI, Distr. Line, Distr. Station, etc.)

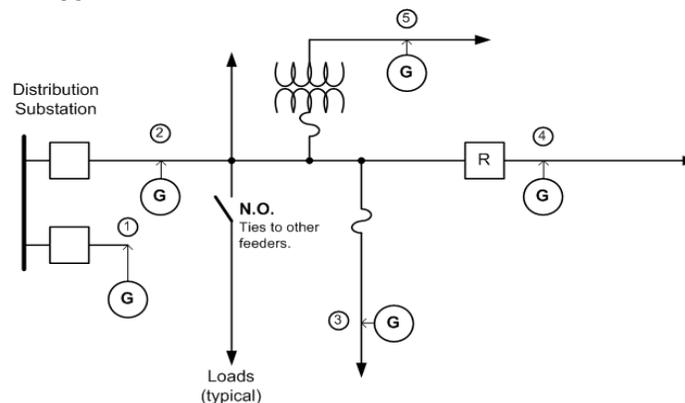
## 6.0 Potential Issues Related to Interconnection

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.

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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 utility 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 overvoltages
  - 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 and without degradation of EPS safety and reliability. It is the intent of any Company study in accordance with 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, DER facilities connected to various locations on the radial distribution EPS (see Illustration 6.5-1) 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 6.5-1: Typical DER 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. Studies will be more complex and accommodating interconnections will likely require more involved infrastructure development, costs, and duration to construct.
  1. 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).
  2. 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.
7. 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 2098**. 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.<sup>8</sup>

## 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 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.

- For inverter based generation, this shall refer to the nameplate rating of the inverter(s). 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 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.

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<sup>8</sup> See Section 3 in the Company's ESB750 for more information on multiple service requests.

- 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.

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 MA SIDG 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 parallel generators 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 Single Phase

Single phase parallel generator 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:

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

### 7.1.2 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 shall not exceed 10 MW covered by the RI SCDG. For more than 10 MW, refer to ESB 756 Appendix A.

### 7.1.3 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%.

### 7.1.4 Neutral Stabilization, Ground Faults, and Grounding

1. Where the Customer is served from a Company multi-grounded distribution circuit, an effectively grounded system with respect to the Company's EPS must be provided to avoid distribution circuit over voltage during accidental isolation of the line from the main system. This may require an additional ground source. Adequate grounding can be provided either by the use of wye-delta main power transformer or

- by installing an appropriate grounding means (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 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:
    - 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).
    - 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-Generator's interconnection. Hence, it is required that the Customer-Generator 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-Generator to mitigate the increase in fault current.
    - If the Customer is permitted to interconnect through an un-grounded source, a "zero-sequence" voltage or "3V<sub>0</sub>" scheme will be required on the primary side of the approved delta primary wound transformer (see Figure 5) supplying the DER system.
  3. As a minimum, the Customer's DER system equipment shall be grounded in accordance with the latest requirements of the National Electrical Code (NEC). For specific installations, refer to the applicable sections of this document and the Company's ESB 750.

## 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. Permanent Plaques: The Interconnecting Customer shall install and maintain clearly labeled permanent plaques in accordance with NFPA 70 (National Electrical Code) and RIPUC 2163.
3. For large DER 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 752, 753, or 758 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 Electric

Tariff, R.I.P.U.C. 2178, describes qualifications for net 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<sup>9</sup> 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 customer shall provide a telecommunications line to each Company-owned revenue meter location. 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.

### **7.2.3 Company Revenue Metering Requirements (RI Re-Growth Program)**

RI RE-Growth DER projects require a separate meter for DER metering such that two meters are normally installed including the supply meter at each location. The service supply to the two meters can be a one combined service connected to a multi-gang meter socket and then split for the final meter connections; see the Company's ESB 750.

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 RE-Growth is only acceptable at the weatherhead.

## **7.3 Transformer**

### **7.3.1 Secondary Served DER 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 500 kVA where the non-DER premises electricity use is 500 kVA or less. 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-Generator'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. 2130 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
2. Interconnection of DER to the customer side of the transformer creates undesirable effects on the company system.
3. 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.
4. 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 DER 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

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<sup>9</sup> "Detented metering" is measuring and registering power flow in a single direction by either mechanical, or electronic, or programming means in a revenue meter.

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 in the impact and detailed studies.

#### **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.

The Company requires 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. Effective grounding may be accomplished with the following configurations:

1. A wye-grounded to wye-grounded transformer with a grounded generator source.
2. A wye-grounded connected primary winding with a fully insulated neutral and the secondary winding to have a delta connection. 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.
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.
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.

Any DER or aggregate DER below 500 kW in a Customer's facility may be permitted to utilize a primary delta - 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 kW and above depending on DER saturation and other conditions on individual feeders.

#### **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. Refer to Section 5.3.4 for specific grounding requirements.

## **7.4 Manual Generator Disconnecting Means**

The Customer-Generator'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 need to be de-activated, however the Company reserves the right to operate the DER disconnect directly in emergency situations.

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The Customer shall provide contact information for Customer personnel that can be reached 24/7, should complications arise with access to the Customer's equipment. Should there be any complications with Company access to the DER disconnecting means, the Company reserves the right to disconnect the Customer's service in its entirety via the next upstream Company owned disconnecting means.

The disconnecting means shall have the following characteristics:

1. According to the RI SCDG, 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).
2. Rating: Disconnecting means shall be rated to interrupt the maximum generator output; meet applicable Underwriters Laboratories (UL), American National Standards Institute (ANSI), and IEEE standards; and shall be installed to meet the NEC and all applicable local, state, and federal codes.
3. Arrangement: The connection of the disconnect switch shall have the line connection (i.e., jaw side) of the switch made to the utility source and 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.
4. Location and Type:
  1. For those 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 ("knife 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. The Company shall exercise such right in accordance with Section 7.0 of RIPUC 2163
  2. For those 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 in the form of 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. The disconnecting means shall be installed between the DER system and the point of connection to the Customer's premises wiring system in accordance with the NEC. For installations above 600 V, the visual open of all three phases shall be capable of being observed without opening the equipment.
  3. 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. 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.
  4. The location and type of disconnecting means for all DER projects will be reviewed on a case by case basis to confirm whether the Customer's proposed equipment is appropriate.
5. Access and Locks: The disconnecting means must be readily accessible at all times to the Company to electrically isolate the Company's Distribution EPS from the Customer's generator facilities. In all instances, the disconnecting means shall have provisions to be locked in the open position with space for Company and Customer padlocks.

6. **Maintenance:** The Customer is solely responsible for the maintenance of all fuses in fused, blade-type disconnect switches.
7. **Identification:** All required disconnecting means shall be identified by a permanent sign as required by the NEC and the ESB 750.

## 7.5 Generator Interrupting Device Requirements

### 7.5.1 General

1. For any aggregate generation connected to a common feeder that is equal or above 500 kW, an interconnection interrupting device such as a circuit breaker shall be installed at the Customer's site. The 500 kW criteria is 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. When a local power supply source is utilized, generator interconnection interrupting devices shall have DC trip coils and tripping energy.
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 Utility 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-Generator 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. The Interconnection Customer is 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-Generator 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-Generator'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 DER 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.

### 7.6.1 **Type Tested (Certified) Equipment**

Protective equipment that has been type tested and recognized under UL Standard 1741.1 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<sup>10</sup> 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**

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), is acceptable. If the Customer

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<sup>10</sup> See definition of "utility grade" for protective device equipment in Section 4.

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 initiate trip to the Company-designated generator interrupting device. Auxiliary relays, where used, shall be fail safe and utility grade.

#### **7.6.3.1 Certified Inverter-based Energy Resource Protection Requirements**

IEEE 1547 compliant and UL-1741 certified<sup>11</sup> 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 and its amendments ("IEEE 1547"). The amendment to the standard, IEEE 1547a, requires voltage and frequency ride through capabilities be available in all inverter based generation. The Customer-Generator shall provide the voltage and frequency ride through capabilities as specified in IEEE 1547a in any inverters installed as part of a DER facility proposed to interconnect to the Company's EPS. The voltage regulation and ride-thru capabilities shall be turned OFF unless otherwise required by the Company.

##### **7.6.3.1.1 Individual Certified Inverter-based Energy Resources below 500 kW**

If the inverter is IEEE 1547 compliant and UL-1741 listed, the internal relays are considered as the only required protection and an additional utility grade relay is not necessary 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 and voltage controlled overcurrent 51C.

##### **7.6.3.1.2 Individual Inverter-based Energy Resource equal or above 500 kW**

IEEE 1547 compliant and UL-1741 listed inverter internal relay functions are considered as primary protection. The Company requires one additional utility grade relay to be installed as secondary the utility grade protection for inverter-based solar PV generation equal or greater than 500 kW. The 27, 59, 81U/O, voltage controlled phase overcurrent 51C, and 51N or 51G elements shall be activated in the secondary utility grade protection relay. The Customer-Generator 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.

The utility grade relay failure alarm shall be wired to initiate trip to the Company-designated generator interrupting device. If two utility grade relays are used to provide the above functions, failure of either relay, or both, being out of service shall trip the interrupting device.

#### **7.6.3.2 All Non-Certified Parallel Generation**

##### **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 relaying and additional protective elements to be active in the utility grade relay(s).

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<sup>11</sup> See definition for "certified" in Section 4.

#### **7.6.3.2.2 Energy Resources equal or above 500 kW**

For any non-certified generator equal or above 500 kW, if the generator is equipped with internal relays with 27, 59, and 81U/O relays, one utility grade relay is required to be installed as the secondary protection. 27, 59, 81 U/O, and overcurrent elements for both phase and ground shall be active in the redundant relay. Otherwise, two utility grade relays and one Company-designated interrupting device shall be installed to meet the protection requirements. 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.

#### **7.6.4 Instrument Transformers for Protective Device 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.

##### **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.

#### **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.

- **AC Inputs:** Each relay shall have its own AC test switch. DC inputs or outputs are not permitted on AC test switches.
- **DC Inputs and Outputs:**
  - 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-Generator'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 requirements including 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 requirements including capability for under frequency ride through. The under-frequency trip setting shall not be higher than 58.9 Hz, as to not conflict with the under frequency load shedding schemes on the Company's EPS. For adjustable under frequency settings in table 2 of IEEE 1547, the chosen setting shall not fall within the prohibited region of NERC PRC-024-2. See Table 7.6.12.1-1 below for default frequency relay settings.

#### **7.6.9 Synchronizing Devices**

The DER 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. For inverter-based systems, a voltage controlled phase element (51C) is required. These relays shall utilize voltage sensing via the Yg-Yg VTs specified in section 7.6.4.2

#### **7.6.11 Utility Grade Protective Device Settings and Verification**

##### **7.6.11.1 Default Voltage and Frequency Set Points for All Types of 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 Parallel Generation Default Voltage & Frequency Set Points**

DEVICE	PICKUP RANGE	TIME DELAY RANGE (sec)	DEFAULT TIME DELAY (sec)
Under Frequency (81U)	$\leq 56.5$ Hz	0.16	0.16
Under Frequency (81U)	$< (58.9 - 57.1)$ Hz adjustable Default set to 58.5 Hz	0.1 – 300.0	300
Over Frequency (81O)	$61 \text{ Hz} \leq f < 62.0$ Hz	0.1 – 300.0	300
Over Frequency (81O)	$> 62.0$ Hz	0.16	0.16
Under Voltage (27)	$< 50\%$ of Nominal	0.1 – 11.0	0.16
Under Voltage (27)	$50\% \leq V < 88\%$ of Nominal	0.1 – 21.0	2
Over Voltage (59)	$110\% < V < 120\%$ of Nominal	0.1 – 13.0	1
Over Voltage (59)	$\geq 120\%$ of Nominal	0.16	0.16

Settings other than the default 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.

**7.6.11.2 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 (kW)	Max. Frequency Difference ( $\Delta f$ , Hz)	Max. Voltage Difference ( $\Delta V$ , %)	Max. Phase Angle Difference ( $\Delta \Phi$ , degrees)
0-500	0.3	10	20
>500 – 1,500	0.2	5	15
>1,500 – 10,000	0.1	3	10

**7.6.11.3 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.

**7.6.11.4 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:

- control wiring verified against the accepted design drawings, and,
- the calibration test performed satisfactorily according to the relay setting document of the accepted design.

The Company reserves the right to witness the Customer’s functional test of the required devices, i.e., trip tests. The Customer-Generator shall submit a witness test plan to the Company for review at least 4 weeks prior to the scheduled witness test. If needed, consult the Company for guidance on preparing a witness test plan. This activity will normally be performed on a schedule as specified by Section 4.2.4 in the **RI SCDG**.

The Customer shall be responsible to specify the settings, calibrate, test, and maintain the balance of their equipment.

### **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-Generator may propose alternative methods of anti-islanding protection of their own generation facility, although it is the Customer-Generator'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 National Grid 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 voltage or provide Var support functions. Any inverter type generation established as voltage regulating or Var supportive will be reviewed under section 7.6.12.4 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  $\leq 33\%$  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 National Grid'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
  - a. DER  $\geq$  300 kW and DER > 33% minimum load and is connected to < 5 kV EPS.
  - b. DER 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<sup>12</sup>
  - a. If line faults (phase and ground where applicable) cannot be cleared by DER protective device or the Company's PCC recloser.<sup>13</sup>
  - 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-Generator'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 Certified DER<sup>14</sup>

1. All inverters shall have an 88% voltage trip within 2 seconds to be considered in this section.
2. Proposed DER rated  $\leq$  50 kW
  - a. No requirements.
3. Proposed DER rated > 50 kW and < 1000 kW
  - a. Line section aggregated non-certified DER is  $\leq$  10% of mix.
    - i. No additional requirements.
  - b. Line section aggregated non-certified DER is > 10% and  $\leq$  25% of aggregate DER.
    - i. Sandia screening<sup>15</sup> may be applicable depending on inverter models on segment.

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<sup>12</sup> While the intent of this unintentional islanding protection policy is to encourage DER installations while minimizing inhibitive impacts to the DG installation, National Grid reserves the right and flexibility to enforce protective measures deemed required for the safety and reliability of the EPS.

<sup>13</sup> 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).

<sup>14</sup> Inverter firmware derating is not acceptable for reduction of system size to satisfy thresholds within this document.

<sup>15</sup> The Sandia screens (<http://energy.sandia.gov/wp-content/gallery/uploads/SAND2012-1365-v2.pdf>) are valid only for those certified inverters that have been confirmed, in writing from the manufacturer, to meet the definition of the Sandia Frequency Shift (SFS), or Sandia Voltage Shift (SVS) as positive feedback based methods according to the report or for inverters using impedance detection with positive feedback. SFS and SVS both rely on positive feedback to work.

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

- ii. Company-owned PCC recloser and reclose blocking required if Sandia screens not passed.
  1. Detailed risk of islanding (ROI) study may be performed at the Customer-Generator's request. If results of the detailed study show no significant risk of islanding for a period greater than 2 seconds, then the recloser and reclose blocking is waived.
- c. Line section aggregated non-certified DER is > 25% of all DER.
  - i. NG PCC recloser and reclose blocking required<sup>16</sup>
    1. Detailed ROI study may be performed at the Customer-Generator's request. If results of the detailed study show no significant risk of islanding for a period greater than 2 seconds, then reclose blocking is waived. Company-owned PCC recloser is waived for aggregate DER  $\leq$  67% of line load to generation ratio or < 500 kW.
4. Proposed DER rated DER  $\geq$  1000 kW
  - a. Company-owned PCC Recloser required.
  - b. Reclose blocking required on line segment sectionalizing device if line segment aggregate DER > 50% of minimum load.

#### **7.6.12.4 Non-Certified & Voltage Regulating Inverters, Induction & Synchronous Machines**

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

## **7.7 Monitoring and Control (M&C) at DER Facility**

DER ranging from 250 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 (EMS) and to incorporate the ability for the Company's system operators via EMS 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. Where available, the company will utilize the Company-owned PCC recloser serving the DER installation to obtain Company's operational polling data.
3. 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.
4. 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 EMS-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

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<sup>16</sup> Where feasible, installing a PCC recloser in front of the non-certified DG may reduce or eliminate any further requirements to the subject applicant DG.

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
5kV or below.	500 kW or greater
greater than 5kV but less than 15kV	1 MW or greater
>15kV	1.8 MW or greater

2. EMS-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 EMS-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-Generator’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 EMS 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 EMS-RTU point list for inputs required at the DER system.*

5. When a Company EMS-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-Generator 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.

## 7.8 Voltage and Frequency Control

1. Inverter based generators shall be in compliance with all revisions of IEEE 1547. The amendment to the standard, IEEE 1547a, requires voltage and frequency ride through capabilities be available in all inverter based generation. The Customer shall provide the voltage and frequency ride through capabilities specified by IEEE 1547a in any inverters installed as part of a generator proposed to interconnect on the Company EPS.
2. These capabilities shall be disabled by default unless otherwise approved by the Company.

## 8.0 Testing and Commissioning

1. The Company reserves the right to witness the Customer-Generator's functional testing of the required devices.
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-Generator 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.
5. All required equipment test reports shall be submitted per ESB 751 prior to final TCP acceptance.
6. 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). 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-Generator 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. The Customer-Generator 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-Generator operating and maintenance responsibilities.
4. 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. 2130.
5. Where the Company is requested to supply demand pulse information (either analog or digital), its use is not intended for generator dispatch or control.
6. 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.

## 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 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 Electric Tariff, R.I.P.U.C. 2130 and the limits and cost responsibilities specified in the :

- 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).

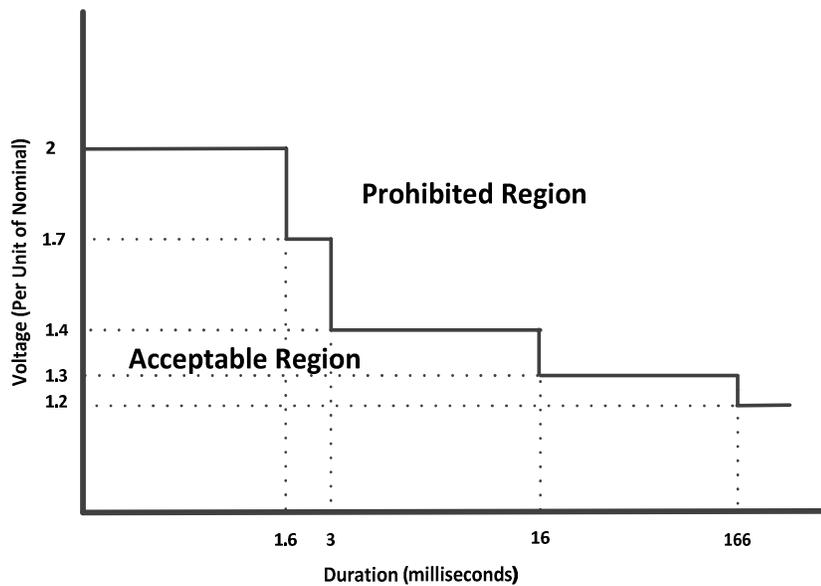
Check service point harmonic distortion to ensure limits specified in ESB 750 and the **RI SCDG** as applicable, are maintained. Current harmonic distortion shall not adversely affect voltage harmonic distortion, the Company Distribution EPS, or service to other customers.

### 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 power quality in accordance with the Company's Electric Tariff, R.I.P.U.C. 2130.
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 adhere to the Transient Over-voltage Tolerance curve as defined in Figure 10.3-1.



**Figure 10.3-1: Transient/Temporary Overvoltage Tolerance Curve**

IEEE 1547 settings require that an inverter-based DER ceases to energize the EPS in 160ms (10 cycles) for an overvoltage of 1.2 per unit (pu) or greater of nominal voltage. This trip point is inadequate to prevent damage to utility and customer equipment depending on the magnitude of the overvoltage per Figure 8.2.3-1 above. These issues could affect the inverter-based DER facility, as well as affect utility and other customer equipment on the feeder.

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 acceptable 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 Figure 8.2.3-1. The letter shall be on the manufacturer’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 Interconnection 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<sup>17</sup> 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.

<sup>17</sup> Refer to Section 7.4 regarding technical requirements for draw-out breakers over 600V and the Company’s electric tariff for limitations of service.

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- 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 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.
- Failure to make available records of verification tests and maintenance of the Customer's protective devices designated by the Company.
- 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

<u>Version</u>	<u>Date</u>	<u>Description of Revision</u>
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 1547a amendment, and technical updates

## 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.
<b>Project Definition &amp; Conceptual Analysis Phase</b>		
1	Customer R.I.P.U.C. 2163 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. 2163 Exhibit I Retail Connection Agreement executed with Customer	Exhibit I
4	Customer commits to Impact or Detailed Study and provides advance payment	5.0
<b>Final Design Review Phase</b>		
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
<b>Installation Progress Review Phase</b>		
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
<b>Installation Compliance Verification Phase</b>		
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
<b>Energization &amp; Synchronization Phase</b>		
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	
24	Customer is permitted to synchronize generation facility in parallel to the Company's supply	
<b>Project Closeout Phase</b>		
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 National Grid Rhode Island Secondary Network EPS Areas**

### **Pawtucket**

[https://www9.nationalgridus.com/narragansett/home/energyeff/network/Eastern/Pawtucket\\_Network\\_Feeder\\_10-02-12.pdf](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](https://www9.nationalgridus.com/narragansett/home/energyeff/network/Eastern/Providence_Network_Feeder_10-02-12.pdf)

National Grid customers in the downtown districts of Pawtucket and Providence should check the National grid 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@nationalgrid.com](mailto:Distributed.Generation@nationalgrid.com) to determine if the proposed location is served in National Grid's Secondary Network area.

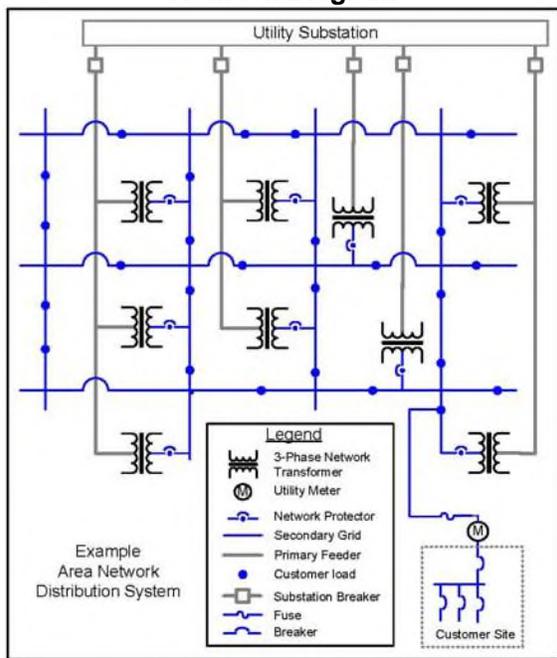
## EXHIBIT 3: Distribution Secondary Grid Network Description

In Rhode Island, National Grid 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.

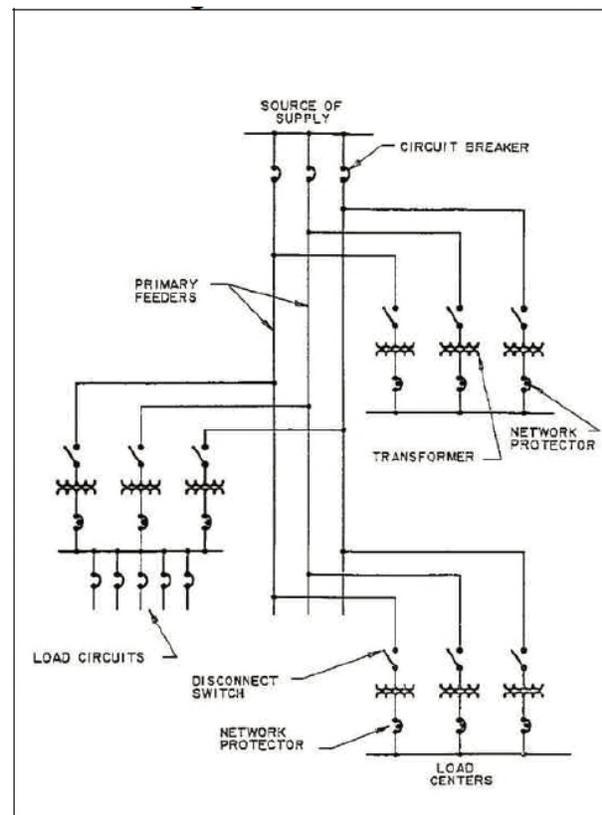
In distribution secondary network systems, devices called "network protectors" are usually arranged to automatically connect its associated transformer to the network system when conditions are such that the transformer when connected will supply power to the network and to automatically disconnect the 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 Grid 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 Spot Network Diagram**



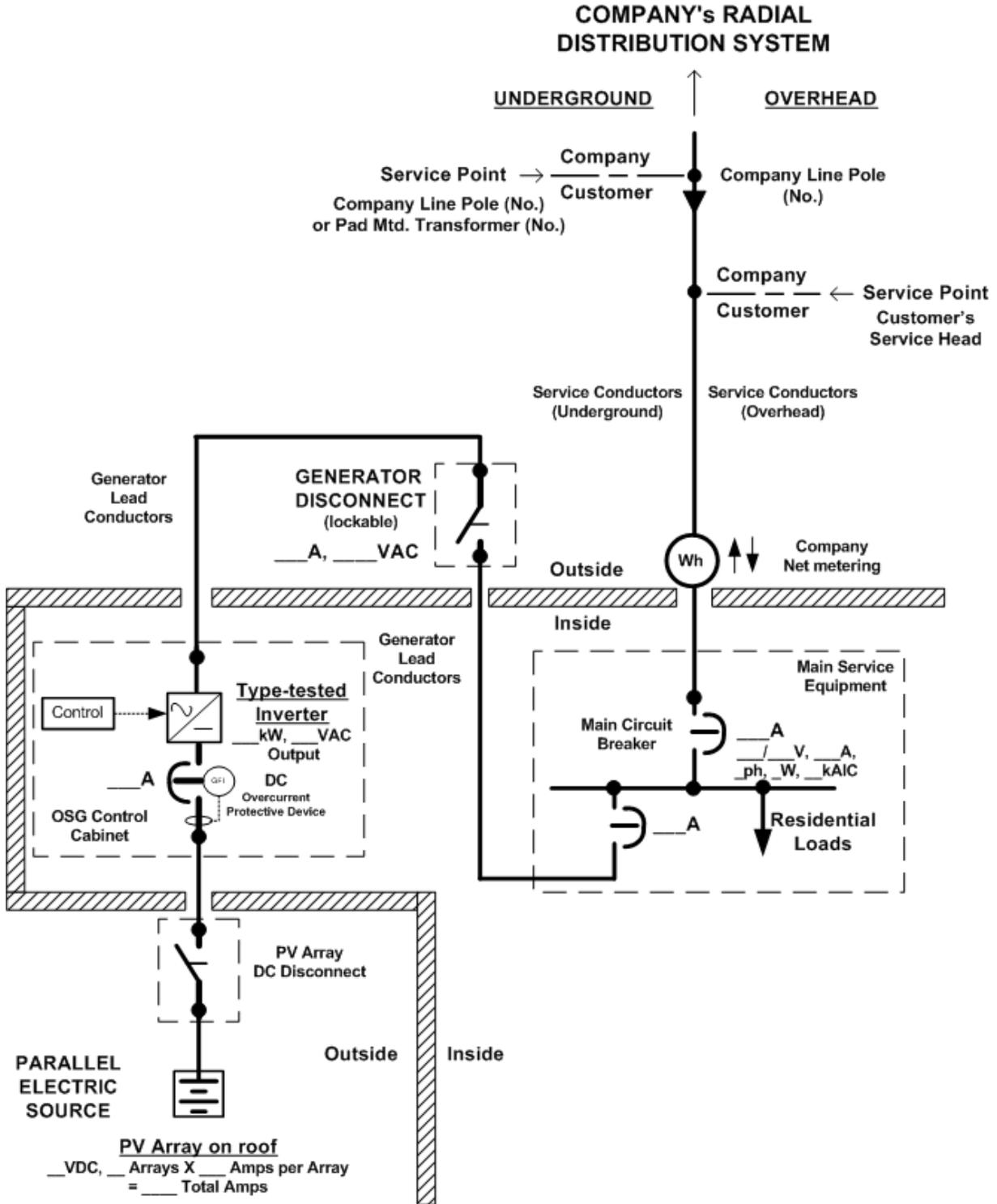
Spot networks are similar to grid (area) networks except they serve a single premise.

## **EXHIBIT 4: Recommended Guidelines for Residential and Commercial Single-line Diagram Submittals**

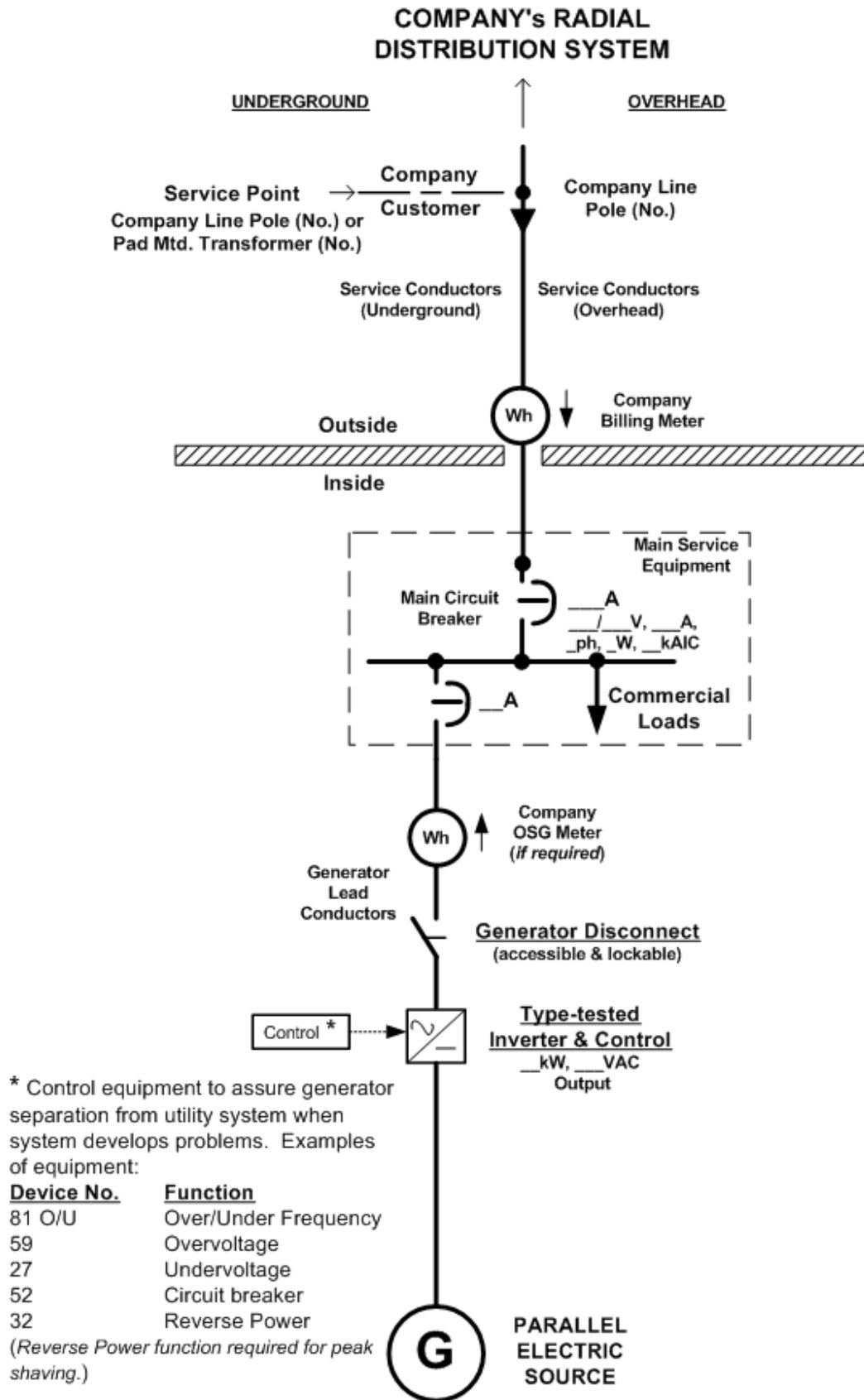
Refer to **Figures 2** and **3** for typical illustration and symbology.

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. Catalog cuts are not required for most major manufacturers. 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.
11. Show connections and ratings of power transformer windings for any to be used.
12. Identify Generator Disconnect and its ratings.

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



**FIGURE 2: Sample Commercial Distributed Generator Installation**



**FIGURE 3: Typical Symbolology for Electrical Drawings**

ELEMENTARY SWITCH DEVICES								CONTACTS AND RELAYS	
FLOW		PRESSURE		LIQUID LEVEL		TEMPERATURE		CONTACTS	
CLOSED RISING	OPENS RISING	CLOSED RISING	OPENS RISING	CLOSED RISING	OPENS RISING	CLOSED RISING	OPENS RISING	NORMALLY OPEN OR "a" CONTACT	NORMALLY CLOSED OR "b" CONTACT
LIMIT				PUSHBUTTON				RELAY COIL	
NORMALLY OPEN	NORMALLY OPEN - HELD CLOSED	NORMALLY CLOSED	NORMALLY CLOSED - HELD OPEN	NORMALLY OPEN	NORMALLY CLOSED				
ELEMENTARY FUSE DEVICES			BATTERY OR DC SOURCE			CONNECTIONS			
FUSE	SOLID LINK	IN REMOVABLE CARTRIDGE OR PULL BLOCK	GENERAL OR SINGLE CELL	MULTI CELL (COMMON)	GROUND	SHORT CIRCUIT (3-PHASE CONNECTION)	SEPARABLE CONNECTORS OR DRAW OUT FEATURE		
DISCONNECTS (UNDER 600 V)		CIRCUIT BREAKERS			TRANSFER SWITCH				
NON-FUSED DISCONNECT	FUSED DISCONNECT	GENERIC OR AIR TYPE	CB OR INTERRUPTING DEVICE (OTHER THAN AIR)		TWO POSITION	THREE POSITION			
CAPACITOR	ANTENNA	THERMAL OVERLOAD	INDICATING LIGHT * = LENS COLOR:						
			A - AMBER B - BLUE C - CLEAR G - GREEN O - ORANGE P - PURPLE R - RED W - WHITE Y - YELLOW						
TRANSFORMERS AND INSTRUMENT TRANSFORMERS									
3-PHASE, WYE		3-PHASE, DELTA					3-PHASE ZIGZAG		
GROUND NEUTRAL	UNGROUND	DELTA	CORNER GROUND	OPEN DELTA	OPEN DELTA CORNER GROUND	BROKEN DELTA	UNGROUND	GROUND	
GENERIC TWO WINDING TRANSFORMER	GENERIC THREE WINDING TRANSFORMER, TERTIARY TYPE		CURRENT TRANS. WITH POLARITY MARKS SHOWN		FUSED POTENTIAL TRANSFORMER				
			EXTERNAL TO BUSHING	BUSHING MOUNTED					
			■ OR • OR ×						

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

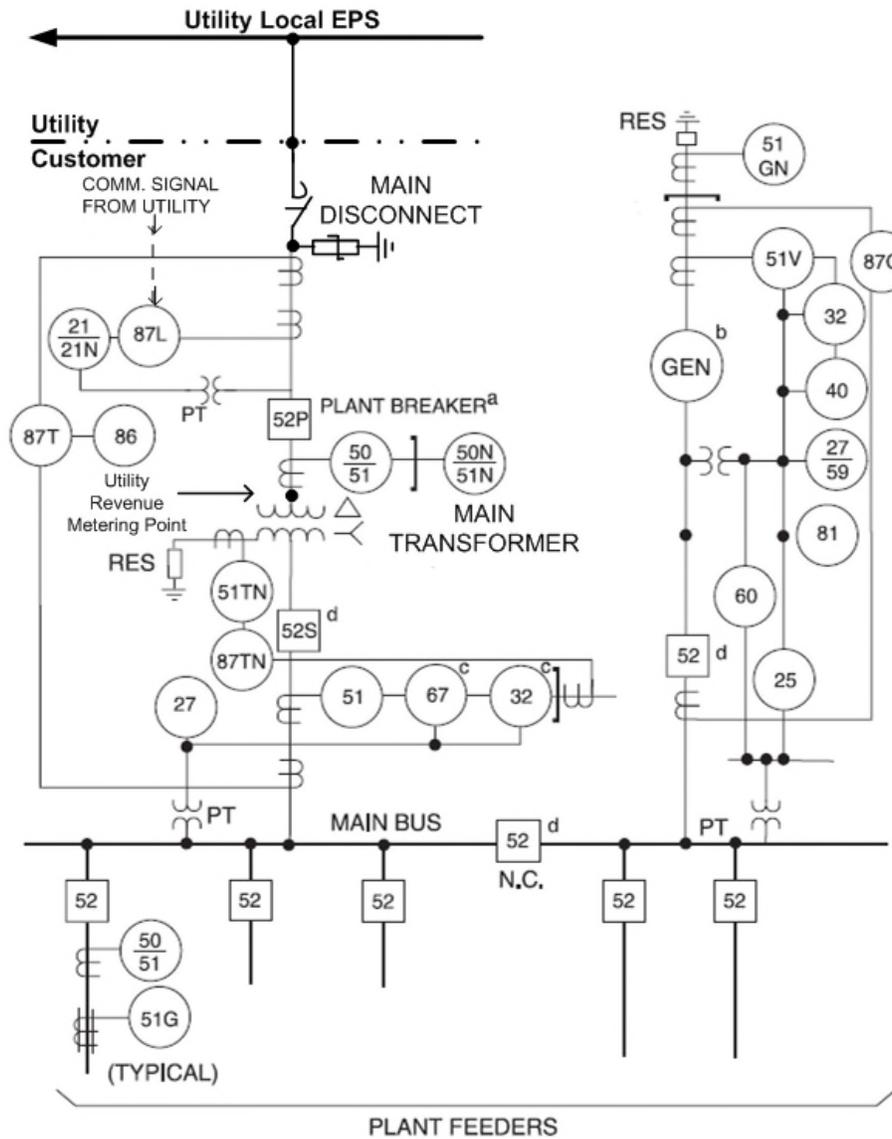
Refer to **Figures 1** and **2** for typical illustrations.

In addition to **Exhibit 4**:

13. 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**):

<b><u>Device Number</u></b>	<b><u>Function</u></b>
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 Voltage Relay
59N	Zero Sequence 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**

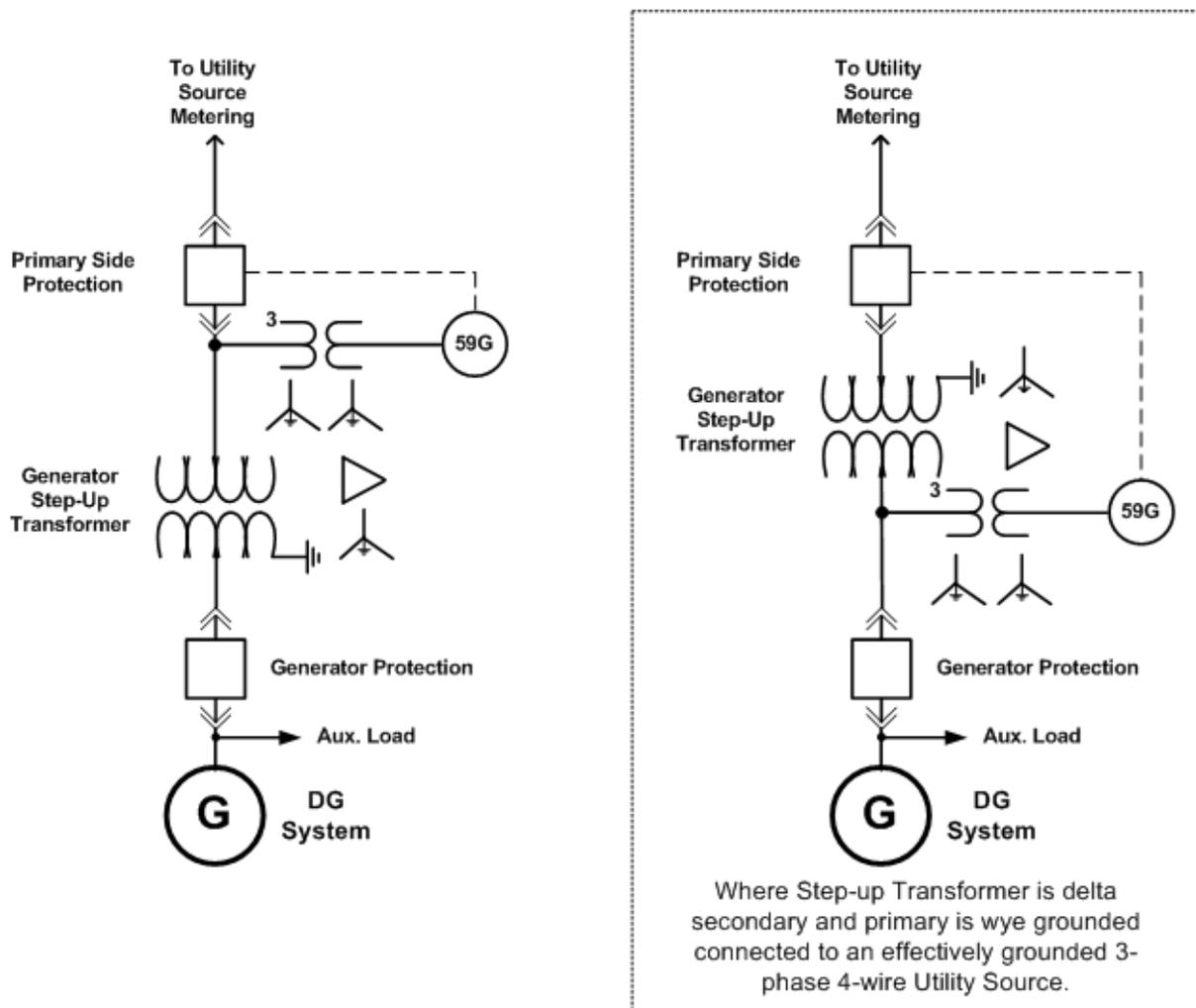


- NOTES:
- a. A fused interrupter switch may also be used instead of the breaker.  
If fused interrupter is used, relaying associated with the transformer is not used.
  - b. In-plant generator for partial plant load and back-up.
  - c. Devices 67 and 32 are directional. Polarity of CTs and PTs must 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 protection on any system that can be a generation source and to protect transformers that can be paralleled and supplied from two sources. In these cases, a “zero-sequence” voltage or “ $3V_0$ ” scheme will be required on the primary side of a delta primary wound transformer supplying the facility. Typically, the added relaying on the primary side of the transformer is a ground overvoltage device function 59N or 59G relay that can detect the presence of the single line-to-ground fault on the Local EPS. This is implemented by installing potential transformers (PTs) on the delta primary system as a source to a voltage sensing relay that would trip the primary side protective device. For a delta secondary wound transformer supplying the facility, the same “zero-sequence” voltage or “ $3V_0$ ” scheme is required on the secondary side but will open the transformer primary side protection.

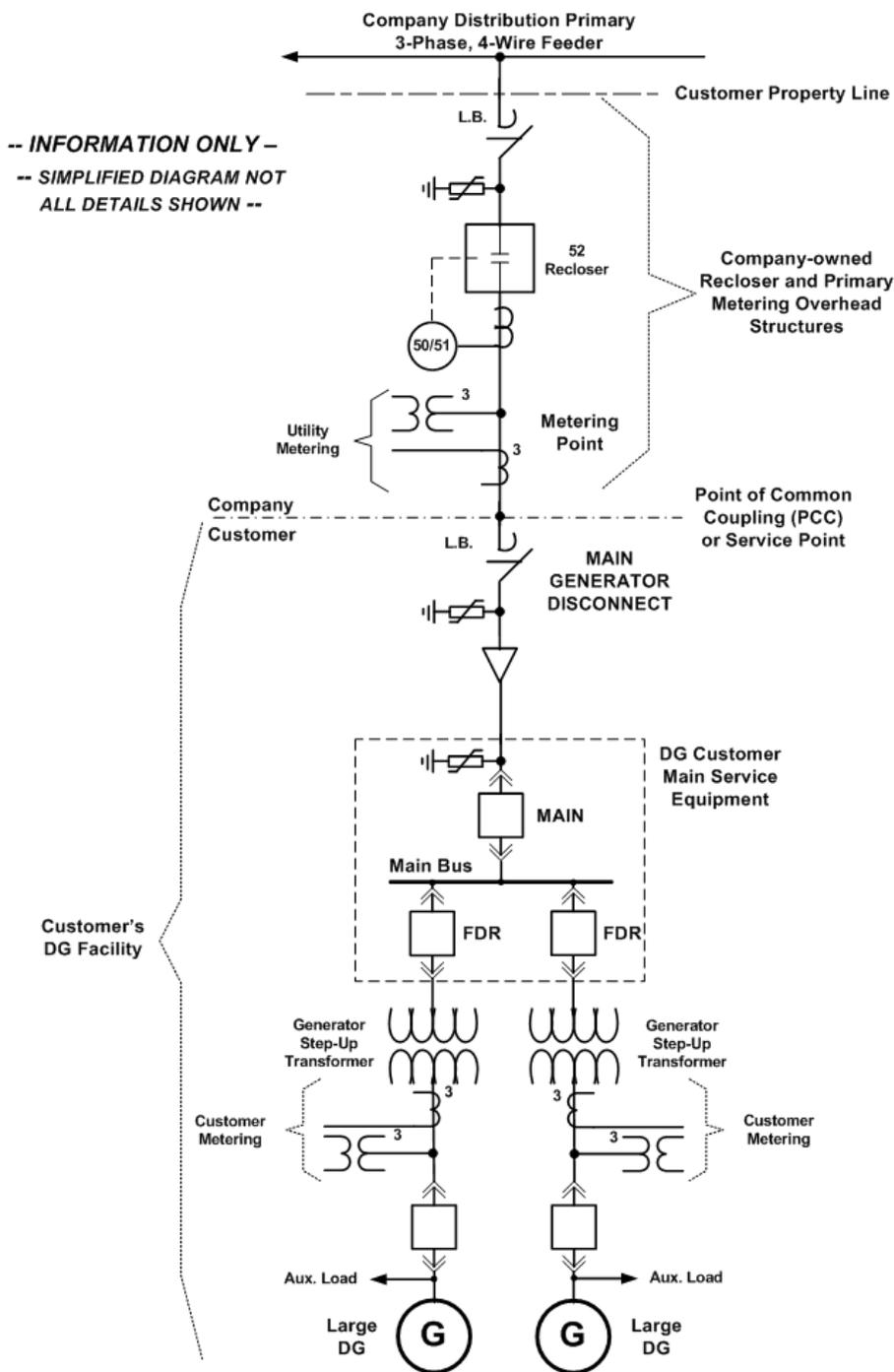


-- INFORMATION ONLY --  
-- SIMPLIFIED DIAGRAMS NOT ALL DETAILS SHOWN --

## EXHIBIT 6: Typical Overhead Primary Service Configuration for Large DER Installations 500 kW and Above

The DER 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 DER Customer.

All Company-owned service lateral facilities and equipment on private property will require easements. These easements will be the responsibility of the DER 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)