# Attachment H: Small Generator (10 MW and Below) Technical Requirements and Standards

## Scope

*The PJM Small Generator Interconnection Applicable Technical Requirements and Standards ("Small Generator Standards") shall apply to all new generator interconnections, within the PJM footprint, with an aggregate size of 10 MW and below at the point of interconnection.*

*The Small Generator Standards shall be read and construed as to be consistent with the PJM Open Access Transmission Tariff ("Tariff"). In the event of any inconsistency between the terms and conditions of the Small Generator Standards and the terms and conditions of the Tariff, the terms of the Tariff shall control. All terms contained in the Small Generator Standards shall be defined as defined by the Tariff. While PJM strives to ensure that the information reflected herein is complete, accurate and reliable, it expressly disclaims any warranty, whether express or implied, as to information contained. Entities relying on the information contained herein do so at their own risk.*

## Purpose

*To align the applicable technical requirements used within PJM with the IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems, and to facilitate the pre-certification of manufactured generation equipment and systems for use within PJM.*

## Background and Discussion

*Developed by the PJM Small Generator Interconnection Working Group ("SGIWG"), the Small Generation Standards define the uniform technical requirements that each Interconnected Transmission Owner ("ITO") and Electric Distribution Company ("EDC") requires for interconnecting to their facilities. The requirements as defined herein will govern for the interconnection of distributed generation 10 MW and below.*

*ITOs and EDCs may, by mutual agreement, elect to waive certain IEEE 1547 requirements and associated exceptions and conditions stated herein, but may not add requirements to IEEE 1547 other than the exceptions and conditions contained herein. For small generators qualifying for interconnection under state rules, the state-approved technical requirements and procedures shall govern. In the event that a small generator has interconnected under state rules and thereafter elects to participate in any PJM market, such small generator must comply with the terms of PJM's Small Resource Interconnection Procedure Manual and these Small Generation Standards. The small generator must submit a completed Feasibility Study Request (Attachment N of the Tariff) and will be responsible for any subsequent study costs. Additionally, the small generator will be required to execute PJM's three-party Interconnection Service Agreement with PJM and the local Transmission Owner, and to the extent applicable, an Electric Distribution Company, as the case may be.*

## General Application Note for Transmission System Interconnections

*In its present form IEEE Standard 1547 is primarily intended to address generator interconnections of 10 MVA or less to radial distribution systems. In order to extend the use of IEEE Standard 1547 beyond this scope to include connection to transmission[1] facilities, it is necessary to clarify the meaning of Section 4.2.1 to assure that system protection requirements are compatible with the established reliability criteria used for those systems.*

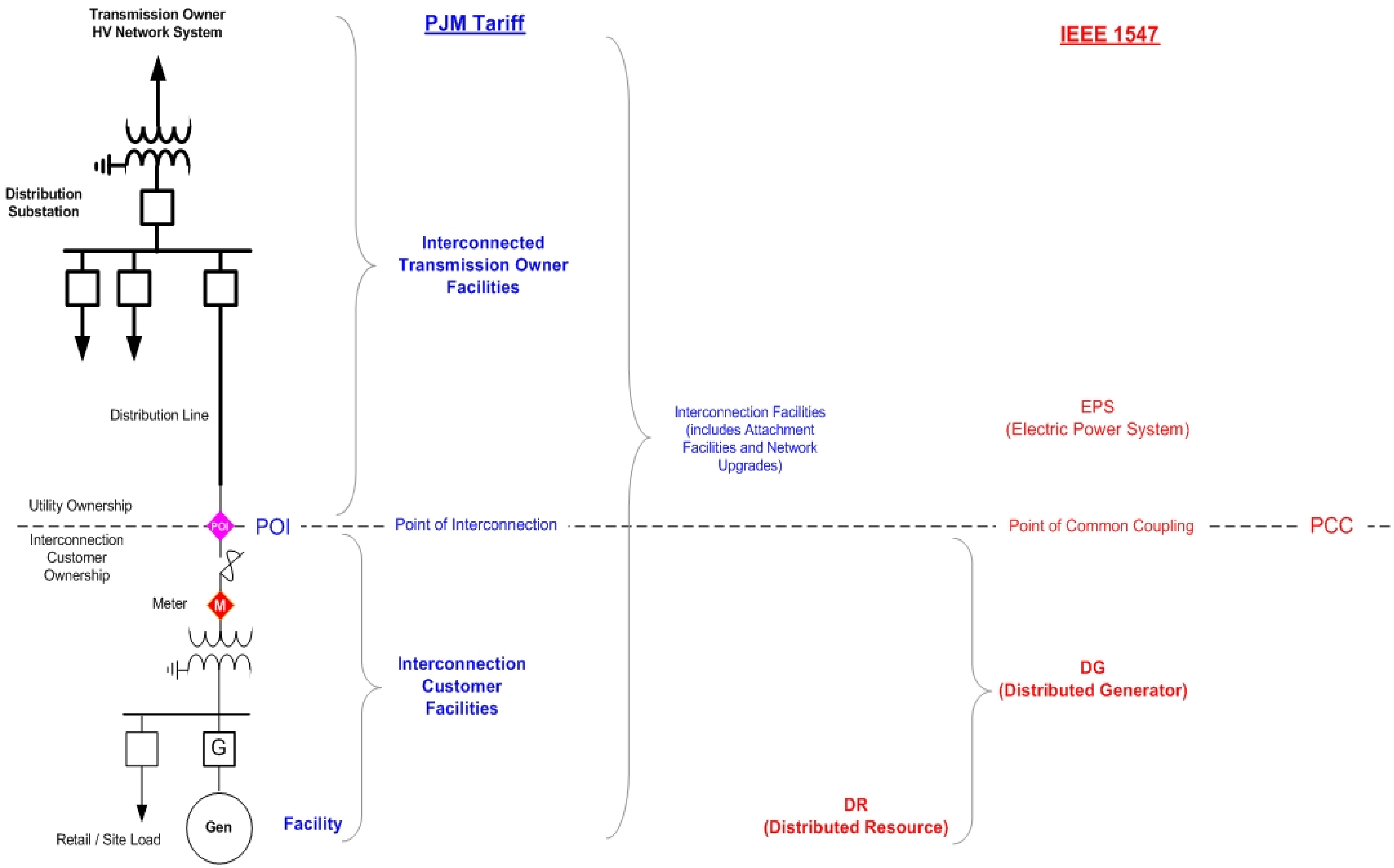
*IEEE Standard 1547 Section 4.2.1 (Area EPS Faults) requires that "the DR unit shall cease to energize the Area EPS for faults on the Area EPS circuit to which it is connected." For transmission Interconnections, this implies that the protection scheme(s) be compatible and coordinate with the Area EPS protection scheme(s) used for the line or substation to which they are interconnected, or be compatible and coordinate with new protection equipment installed due to the connection of the generation to this facility.*

1 In the context used here, transmission systems are systems 69 kV or greater or networked lower voltage systems that are used for backbone energy delivery within smaller geographic areas, much the same as most 69 kV systems.

## PJM Tariff / IEEE 1547 Definition Cross-Reference

| *IEEE Standard 1547* | *PJM Tariff* |
|---|---|
| PCC (Point of Common Coupling) | POI (Point of Interconnection) |
| Point of DR Connection | Not Applicable |
| EPS (Electric Power System) | Interconnected Transmission Owner Facilities |
| Area EPS Operator | Interconnected Transmission Owner |
| Not Applicable | Transmission Provider (PJM) |
| DG (Distributed Generation) | Interconnected Generation Customer Facilities which are not connected to the Bulk Power Transmission System |
| DR (Distributed Resources) | Interconnected Generation Facility which is not connected to the Bulk Power Transmission System |
| Interconnection Equipment | Not Applicable |
| Interconnection System | Interconnection Facilities |
| Not Applicable | Interconnection Customer Facilities |
| Electric Power System, local | Not Applicable |
| Electric Power System, area | Not Applicable |
| Cease to Energize<br>(Cessation of energy outflow capability) | Not Applicable |

*Note: The illustration below is for cross-reference of PJM Tariff and IEEE 1547 terms only.*



## Applicable Technical Requirements and Standards

*IEEE Standard 1547 shall constitute the total technical requirements and standards for interconnection of small generators of 10 MW and below with the following noted exceptions, additions, and clarifications. IEEE Standard 1547.1 constitutes the requirement for test conformance to IEEE Standard 1547.*

| *IEEE Standard Requirement* | | *Exceptions or Additions* |
|---|---|---|
| *4.1.1* | *Voltage Regulation* | *None. See Application Note 1.* |
| *4.1.2* | *Integration with Area EPS Grounding* | *None. See Application Note 2.* |
| *4.1.3* | *Synchronization* | *None. See Application Note 3.* |
| *4.1.4.1* | *Distribution Secondary Grid Networks (under development)* | *None. See Application Note 4.* |
| *4.1.4.2* | *Distribution Secondary Spot Networks* | *Exception. ComEd only allows Spot Network interconnections on an exception basis or where state commission regulations specify requirements.* |
| *4.1.5* | *Inadvertent Energization of the Area EPS* | *None.* |
| *4.1.6* | *Monitoring* | *None. See Application Note 5.* |
| *4.1.7* | *Isolation Device* | *None. See Application Note 6.* |
| *4.1.8.1* | *Protection from EMI* | *None.* |
| *4.1.8.2* | *Surge Withstand Performance* | *None.* |
| *4.1.8.3* | *Paralleling Device Withstand* | *None.* |
| *4.2.1* | *Area EPS Faults* | *PEPCO and PSEG exception for Islanding protection. See Application Notes 7 and 12.* |
| *4.2.2* | *Area EPS Reclosing Coordination* | *None. See Application Note 13.* |
| *4.2.3* | *Voltage* | *None. See Application Note 8.* |
| *4.2.4* | *Frequency* | *None.* |

| *IEEE Standard Requirement* | | *Exceptions or Additions* |
|---|---|---|
| *4.2.5* | *Loss of Synchronism* | *None.* |
| *4.2.6* | *Reconnection to Area EPS:* | |
| | *(a) Voltage Requirement* | *None. See Application Note 9.* |
| | *(b) Frequency Requirement* | *None. See Application Note 9.* |
| *4.3.1* | *Limitation of DC Injection* | *None.* |
| *4.3.2* | *Limitation of Flicker induced by the DR* | *None. See Application Note 10.* |
| *4.3.4* | *Harmonics* | *PPL exception. See Application Note 11.* |
| *4.4.1* | *Unintentional Islanding* | *PEPCO and PSEG exceptions.*<br>*See Application Note 12.* |
| *5.1* | *Design Test* | *None. See Application Note 14.* |
| *5.2* | *Production Tests* | *None. See Application Note 14.* |
| *5.3* | *Interconnection Installation Evaluation* | *None.* |
| *5.4* | *Commissioning Tests* | *None.* |
| *5.5* | *Periodic Tests* | *None.* |

## Application Notes

**1.** 4.1.1 Voltage Regulation.

*Depending on size of generation (relative to EPS strength) and location of interconnection, the interconnected generation may be required to provide or absorb reactive power and/or follow a voltage schedule to maintain an acceptable voltage profile on the EPS with the addition of the new generating facility.*

**2.** 4.1.2 Integration with Area EPS grounding.

*Where new transformers are required:*

- AP requires a wye-grounded connection on the T.O. side of the DG step up transformer; and
- PEPCO's requirement for an isolation transformer including its configuration at 13.8 kV and above, will be determined on a case by case basis and will depend on the generating facility's location and system configuration.

*AP and PEPCO requirements specified above do not apply if a generator is being connected to a system on the low voltage side of an existing Interconnection Customer transformer.*

*Other Transmission Owners within PJM will accept a delta or wye-ungrounded connection provided that adequate protection is provided by the DG to detect a ground and limit any overvoltage to an acceptable level on the TO's system. Adequate protection includes voltage monitoring on the high side of the DG main transformer using phase to ground connected VTs. Also see Application Note 5 for an additional AEP Application Note for grounding coordination related to operation of isolating devices.*

**3.** 4.1.3 Synchronization.

*IEEE 1547 Synchronization voltage fluctuation requirement of +/- 5% is applicable as stated. Flicker requirement 4.3.2 guidance is provided by IEEE Standard 519 and IEEE Flicker Task Force P1453. However, the requirement which must be met for 4.3.2 is to not cause voltage and /or frequency disturbances which are objectionable to other EPS customers during actual operation of DR.*

**4.** 4.1.4.1 Distribution Secondary Grid Networks.

*IEEE 1547 presently does not address the requirements for Secondary Grid Networks. These interconnection requests will be evaluated on a case by case basis.*

**5.** 4.1.6 Monitoring.

*"Each DR unit of 250 kVA or more or DR aggregate of 250 kVA or more at a single PCC shall have provisions for monitoring its connection status, real power output, reactive power output, and voltage at the point of DR connection." Local monitoring provisions,*

*such as panel meters and indicating lights, may be acceptable to meet these requirements in certain cases.*

A. An Internet-based SCADA alternative (see Informative Annex #2) was developed as a reliable and economical alternative to direct SCADA communications with the TO. In addition to generally lower installed cost for the "Internet SCADA alternative," the Internet ongoing communication costs may be more cost effective to other alternatives, especially those that require leased telephone circuits.

> ***NOTE:*** *Informative Annex #2 is available on the PJM Web site (www.pjm.com) by following the site menu for Planning > Reliability Planning Process > Expansion Planning Process and then selecting from among the 10 specific documents listed under the heading "Annex #2 References for Manual 14D, Attachment H."*

B. When full-time dedicated SCADA communications are required (see Transmission Owner ("TO") listing below and refer to the SCADA REQUIREMENTS spreadsheet - Informative Annex #1) the DG Owner, PJM or the TO will provide and/or install a suitable SCADA Remote Terminal Unit in accordance with the specifications provided in Informative Annex #2 or an alternative mutually suitable to the DG Owner, Transmission Owner and PJM.

C. The PJM TOs agree to accept the "Internet SCADA alternative" (see Informative Annex #2), in lieu of direct SCADA communications with the TO, except in circumstances where the "Internet SCADA alternative" does not meet certain TO technical requirements specified and justified by the TO.

D. If the TO, PJM and DR owner mutually agree, specifications for other suitable interfaces between the DG and TO SCADA can be acceptable. Where applicable, this approach would allow a DR owner to use a SCADA protocol of their choice and provide an interface closer to the Transmission Owner's SCADA facility. Such an installation must provide adequate communication performance, suitable to PJM and the TO.

*Installation of communications facilities (internet service, leased telephone circuits, fiber optics, etc.), communications facility Operation and Maintenance, and other ongoing costs are the responsibility of the Interconnection Customer.*

*Installation of communications facilities (typically leased telephone circuits), communications facility Operation and Maintenance, and other ongoing costs are the responsibility of the Interconnection Customer.*

*PJM requires real-time telemetry data (MW and MVAR) for Capacity Resources, Energy Resources 10MW and above, or Energy Resources able to set LMP. PJM also requires interval revenue metering data (KWH and KVARH data at 5 minute intervals provided hourly).*

*See the following for specific interconnection requirements based on Transmission Owner Zone:*

*Allegheny Power—Requirement for SCADA is determined on a case-by-case basis by Allegheny Power.*

*American Electric Power—Real-time telemetry (SCADA) generally required for generation greater than 2.5 MW connected to the distribution system and all connections at transmission voltages.*

*Baltimore Gas and Electric—Requires BG&E specified telemetry (periodic, not real time), installed by BG&E, for all generator interconnections.*

*Commonwealth Edison Company—Requires real-time telemetry for any interconnection of 10 MW or greater, or for interconnections where transfer trip is required (generally 2.5 MW and above) for the interconnection.*

*Dayton Power and Light—Determines real-time telemetry (SCADA) requirements on a case-by-case basis.*

*Dominion—Requires a SCADA RTU compatible with Dominion's SCADA system when the ratio of "Light Local Load" to Maximum Rated Generation Capacity ratio is less than 5.*

*Duquesne Light Company—At DLC's discretion the Interconnection Customer can be required to install and maintain a dedicated communications link, compatible with DLC's equipment, to provide telemetry (SCADA) to DLC's Operation Center. The preferred communications protocol for RTU communications is DNP 3.0. The installed SCADA shall comply with the current NERC Cyber Security standards.*

*First Energy—FE determines real time telemetry (SCADA) requirements on a case by case basis for interconnection to the radial distribution system. Real time telemetry is required for all interconnections to the transmission system, generally 23 kV and above.*

*Old Dominion Electric Cooperative—ODEC requires real-time SCADA for DG resources in the 2-10 MW range, to include MW and MVAR and status of the interconnecting circuit breaker. This does not necessarily imply a full RTU but could be a data link with the plant / unit control system. DNP 3.0 is the supported protocol.*

*Orange and Rockland—All facilities over 1,000 kW connected to the distribution system must have equipment to continuously telemeter the following data to Orange and Rockland's Energy Control Center via a leased telephone line. This data will be provided through the installation of a REMOTE TERMINAL UNIT (RTU) in the applicant's facility. The RTU shall use DNP 3.0 protocol (unless otherwise stated).*

*PECO Energy requires real-time telemetry for interconnections of 5 MW or greater.*

*PHI Companies (Atlantic City Electric Co., Delmarva Power & Light Co. and Potomac Electric Power Co.)—Atlantic City Electric Co. and Delmarva Power & Light Co. require a RTU for all generator interconnections, and real-time MWH and MVH telemetry for all interconnections for which generators participate in PJM markets. For generators not participating in PJM markets real-time telemetry is required for generators 3 MW and above.*

> ***Note:** The specific location and circumstances of a generator interconnection may make telemetry necessary, even when telemetry would not ordinarily be required.*

*PEPCO requires a RTU for all generator interconnections, and real time telemetry for all interconnections that participate in PJM markets. For generators not participating in PJM markets real-time telemetry is required for generators 10 MW and above.*

*PPL—Requires full-time dedicated SCADA RTU compatible with PPL EU's SCADA system for interconnections 2.5 MW and above or at 69 kV and above.*

*PSEG—Real-time telemetry (SCADA) requirement is determined on a case-by-case basis. Smaller MW size generator interconnections usually require a low-cost alternative system.*

*UGI—Requires real-time telemetry (SCADA) compatible with the UGI SCADA system for all interconnections 1MW or greater and for all 66 kV and above interconnections.*

**6.** 4.1.7 Isolation Device Requirement.

*When the Area EPS operating practices require an isolation device, that device must be readily accessible to the Area EPS operator, lockable in the open position, and must provide a visible break in the electrical connection between the generator and the Area EPS. The Isolation Device must be rated for the voltage and current requirements of the installation. The Isolation Device may be electrically located anywhere between the point of common coupling and the generator. However, the customer should consider the impact of the electrical location of the Isolation Device. If the Isolation Device is electrically at or near the generator, and the Area EPS Operator uses the Isolation Device to provide clearance for worker safety, the customer will be unable to operate its generator to maintain electric supply to all or a portion of its load on the Local EPS during an outage of the Area EPS.*

*A drawout breaker may be used to meet the Isolation Device requirement if it is lockable in the withdrawn position and has a visible position indicator.*

*For facilities interconnecting at voltages exceeding 600 volts, when required by the EDC, the Isolating Device required to allow EDC personnel to safely isolate the generator must have a ground grid designed and installed in accordance with IEEE 80 and to specifications to be provided by the EDC. This ground grid limits the ground potential rise should a fault occur during switching operations. Operation of this Isolation Device must be restricted to EDC personnel and properly trained operators designated by the Customer. Designated Customer personnel may be required to learn and adhere to the EDC's "Switching and Tagging" procedures.*

**7.** 4.2.1 Area EPS Faults.

*Area EPS Fault Protection requirement for typical interconnection: (Figures 7A, 7B and 7C on the following pages are intended to be representative of typical connections to radial and networked lines, specific requirements will be determined by PJM and the T.O during PJM Feasibility and Impact Studies on a case-by-case basis.)*

**Figure 7A – One-Line Diagram for a Typical Interconnection to a Radial Distribution System**

*Typical Protective Relaying Functional Requirements*

| | |
|---|---|
| 27 | Undervoltage (3 phases, 1 phase if 50/51G can be applied) |
| 59 | Overvoltage (3 phases, 1 phase if 50/51G can be applied) |
| 81O | Overfrequency (1 phase required) |
| 81U | Underfrequency (1 phase required) |
| 25 | Synchronizing check (1 phase required) |
| 32* | Power* (If required, 1 or 3 phase depending on type) |
| 50/51** | Phase instantaneous and time overcurrent (3 phases if required), or |
| 21** | Phase distance relay (3 phases if required) |
| 50/51G*** | Ground instantaneous and time overcurrent (1 if applicable) |

* If required due to reverse power limitations.

** 50/51 or 21 but not both required.

*** Only if transformer / generator connection allows ground fault current contribution to EPS ground fault

*Additional Protective Relaying Functional Requirements (as Required)*

- Dead line closing control (27 and / or 25 function) at EPS source breaker(s), line recloser(s), etc.
- Larger facilities may require the installation of additional equipment such as directional relaying at the substation feeding the circuit.
- Also see Application Notes 7 and 10 for transfer trip and unbalance functional requirements.

- Voltage Unbalance Protection—In accordance with ANSI C84.1, Annex D, Section D.2 Recommendation, voltage unbalance at the point of common coupling caused by the DG equipment under no load conditions shall not exceed 3% (calculated by dividing the maximum deviation from average voltage by the average voltage, with the result multiplied by 100).

> ***Note:*** *The present version of IEEE 1547 is primarily intended to be applicable to interconnection of DR on radial distribution systems (Section 1.3 Limitations - "Installation of DR on radial primary and secondary distribution systems is the main emphasis of this standard,…"). From a practical standpoint, this represents an upper limit of 2.5 to 5 MW on typical 13 kV EDC distribution circuits, unless it is a dedicated circuit constructed for the sole purpose of interconnecting the DR. Larger facilities will generally require interconnection to the EDC's sub-transmission or transmission system. These larger facilities may require additional or specific protection equipment necessary to coordinate with the EDC's protection practices.*
>
> ***Additional AEP Application Note:*** *In its review of the proposed small generator interconnection request, AEP may determine that a lesser percent unbalance limit is required due to voltage unbalance already present from existing customer loads, such as certain compressor motors and power electronic loads, in the electrical vicinity.*

**Figure 7B – One-Line Diagram for a Typical Interconnection to a Looped (Network) System**

*Typical and Additional Protective Relaying Functional Requirements*

- Same as Figure 7A above and others as may be required to be compatible with and coordinate with EPS transmission system protection.
- In general, requirements developed to connect 10 MVA and smaller generation to looped networked sub-transmission systems will be more involved and diverse than those needed for radial distribution systems. Additional considerations may be required.

**Figure 7C – One-Line Diagram for a Typical Interconnection to a Radial Transmission System**

*Typical and Additional Protective Relaying Functional Requirements*

- Same as Figure 7A above and others as may be required to be compatible with and coordinate with EPS transmission system protection.

**Figure 7A – One-Line Diagram for a Typical Interconnection to a Radial Distribution System**

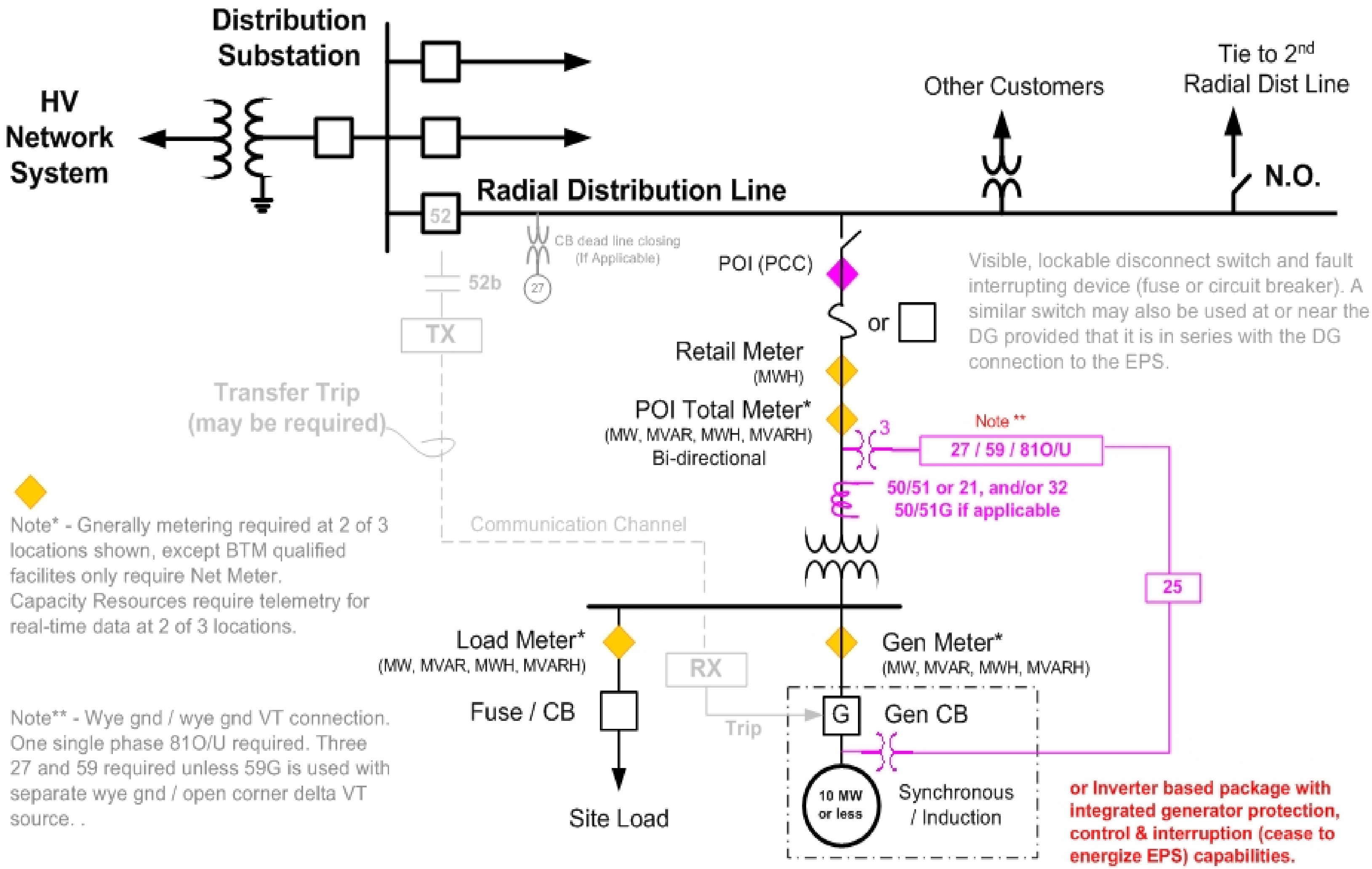


**Figure 7B – One-Line Diagram for a Typical Interconnection to a Looped (Network) System**

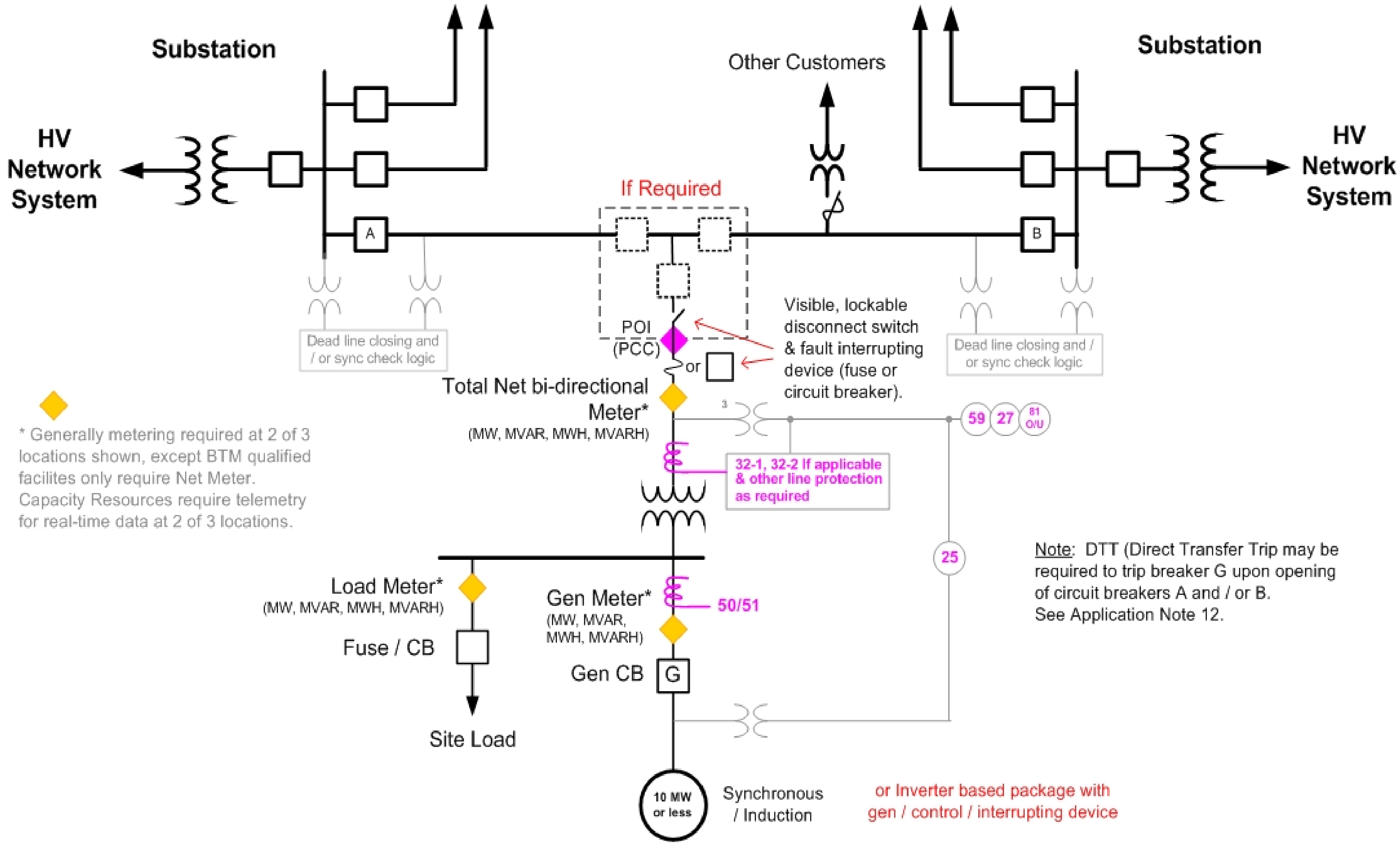
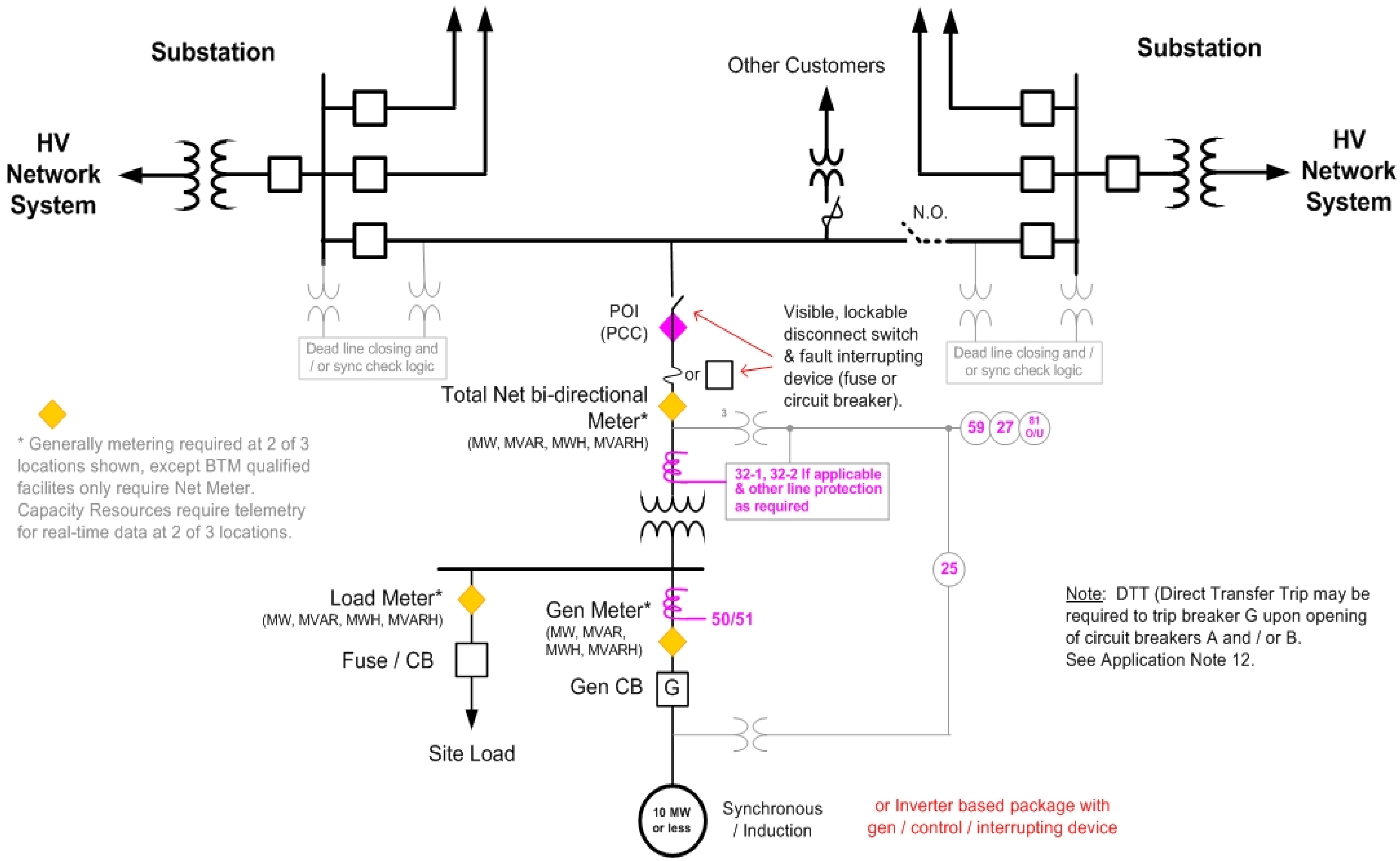


**Figure 7C – One-Line Diagram for a Typical Interconnection to a Radial Transmission System**



**8.** 4.2.3 Voltage.

*In cases where the DG interface is via an ungrounded transformer connection at the PCC, the voltage sensing must be done on the T.O. side of the transformer. This voltage sensing must be Phase - Ground connected for all three phases.*

*Voltage Unbalance Protection. In accordance with ANSI C84.1, Annex D, Section D.2 Recommendation, voltage unbalance at the point of common coupling caused by the DG equipment under no load conditions shall not exceed 3% (calculated by dividing the maximum deviation from average voltage by the average voltage, with the result multiplied by 100).*

**9.** 4.2.6 Reconnection to Area EPS.

*For larger generating units, an Area EPS may require verbal communication with the System Operator before returning generation to the system.*

**10.** 4.3.2 Limitation of Flicker induced by DR.

*Requirement 4.3.2 guidance is provided by IEEE Standard 519 and IEEE Flicker Task Force P1453. However, the requirement which must be met for 4.3.2 is to not cause voltage and /or frequency disturbances which are objectionable to other EPS customers during actual operation of DR.*

**11.** 4.3.3 Harmonics.

*In addition to the IEEE 1547 Harmonics requirement [i.e., each DG installation must, at its PCC, meet the injected harmonic current distortion limits provided in IEEE 1547 Table 3 (excerpt IEEE 519 Table 10.3)] when multiple DG units are operating at different PCCs, each alone may meet the preceding current injection limit. However, the aggregate impact of all the DG units could still cause voltage distortion, which would impact other non-DG customers. Therefore, the aggregate voltage distortion at EACH PCC must also not exceed IEEE 519, Table 11.1. If the limits described in IEEE 519, Table 11.1 are exceeded, the offending DG is responsible for any appropriate corrective actions taken by the interconnecting transmission owner to mitigate the problem. Studies will be performed to determine if excessive harmonic distortion will occur prior to installation of the DG. However, it may not be possible to predict the net level of voltage distortion before each new DG installation on a given circuit. Voltage distortion in excess of IEEE 519 can be used as a benchmark to trigger corrective action (including disconnection of DG units) if service interference exists.*

> ***Additional PPL Application Note:*** *PPL has a requirement for any one Customer (load, generation, etc.) to limit the voltage THD (Total Harmonic Distortion) to 2.5% or less for distribution voltages and 1.5% at 69 kV. PPL allows a smaller fixed limit for each customer thereby sharing allowable harmonic contribution rather than applying a first-come first-served principle to successive interconnection requests.*

**12.** 4.4.1 Unintentional Islanding.

*The Unintentional Islanding requirement can be met by the following:*

E. Transfer trip.

F. Sensitive Frequency and Voltage relay settings, with a short tripping time delay, where the maximum DR aggregate generation net output to the EPS is considerably less than the expected minimum islanded EPS load. Typically the islanded load must be greater than two to three times the maximum net islanded DR output.*

G. DR certified to pass an anti-islanding test.

H. Reverse or minimum power flow Relay limited.

I. Other anti-islanding means such as forced frequency or voltage shifting.

** Exceptions to B above:*

*PSEG—Option B only applicable to aggregate DR interconnections of 1MW and below.*

*PEPCO—Option B generally not applicable for DR interconnections which export energy to the PEPCO system regardless of generation and load mismatch.*

**13.** In accordance with Section 4.2.2 Area EPS reclosing coordination, a 2-second response time may not be adequate to coordinate with the Area EPS reclosing practices. This may result in damage to the generator upon reclosing of the EPS source. In some instances, on a case-by-case basis, the EPS operator may allow the reclosing time to be increased or add synchronism check supervision to provide coordination. Increasing the reclosing time in some cases will have an unreasonable impact on other customers. Other means, such as transfer trip, must then be used to insure isolation of the generator before automatic circuit reclose.

**14.** Options for Satisfying 5.1 Design and 5.2 Production Test Requirements.

*Design and Production tests requirements may be satisfied with certified equipment, although certified equipment is not required, consistent with the following criteria:*

J. The small generating facility equipment proposed for use separately or packaged with other equipment in an interconnection system shall be considered certified for interconnected operation if (1) it has been tested in accordance with IEEE 1547.1 and the appropriate codes and standards referenced below by any Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration to test and certify interconnection equipment pursuant to the relevant codes and standards listed below, (2) it has been labeled and is publicly listed by such NRTL at the time of the interconnection application, and (3) such NRTL makes readily available for verification all test standards and procedures it utilized in performing such equipment certification, and, with consumer approval, the test data itself. The NRTL may make such information available on its Web site and by encouraging such information to be included in the manufacturer's literature accompanying the equipment.

K. The Interconnection Customer must verify that the intended use of the equipment falls within the use or uses for which the equipment was tested, labeled, and listed by the NRTL.

L. Certified equipment shall not require further type-test review, testing, or additional equipment to meet the requirements of this interconnection procedure; however, nothing herein shall preclude the need for an on-site commissioning test by the parties to the interconnection nor follow-up production testing by the NRTL or periodic tests per IEEE 1547 Section 5.5.

M. If the certified equipment package includes only interface components (switchgear, inverters, or other interface devices), then an interconnection customer must show that the generator or other electric source being utilized with the equipment package is compatible with the equipment package and is consistent with the testing and listing specified for this type of interconnection equipment.

N. Provided the generator or electric source, when combined with the equipment package, is within the range of capabilities for which it was tested by the NRTL, and does not violate the interface components' labeling and listing performed by the NRTL, no further design review, testing or additional equipment on the customer side of the point of common coupling shall be required to meet the requirements of this interconnection procedure.

O. An equipment package does not include equipment provided by the utility.

P. Any equipment package approved and listed in a state by that state's regulatory body for interconnected operation in that state prior to the effective date of these small generator interconnection technical requirements shall be considered certified under these procedures for use in that state.

## Relevant Codes and Standards

- IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems (including use of IEEE 1547.1 testing protocols to establish conformity)
- UL 1741 Inverters, Converters, and Controllers for Use in Independent Power Systems
- IEEE Std 929-2000 IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems
- NFPA 70 National Electrical Code
- IEEE Std C37.90.1-1989 (R1944) IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems
- IEEE Std C37.90.2 (1995) IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers
- IEEE Std C37.108-1989 (R2002) IEEE Guide for the Protection of Network Transformers
- IEEE Std C57.12.44-2000, IEEE Standard Requirements for Secondary Network Protectors
- IEEE Std C62.41.2-2002, IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000V and Less) AC Power Circuits
- IEEE Std C62.45-1992 (R2002) IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000V) and Less) Power Circuits
- ANSI C84.1-1995 Electric Power Systems and Equipment -Voltage Ratings (60 Hertz)
- IEEE Std 100-2000, IEEE Standard Dictionary of Electrical and Electronic
- NEMA MG 1-1998, Motors and Small Resources, Revision 3
- IEEE Std 519-1992, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems
- NEMA MG 1-2003 (Rev 2004), Motors and Generators, Revision 1