PSEG Long Island's Smart Grid Small Generator Interconnection Technical Requirements and Screening Criteria for Operating in Parallel with LIPA's Distribution System

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Contents

1. Scope and Purpose

This document defines the technical requirements for interconnection of distributed energy resources (DER), inclusive of both generation and electric energy storage, to Long Island Power Authority (LIPA) distribution systems. These requirements are necessary to protect LIPA system reliability, power quality, safety, system equipment integrity, and the property of other LIPA customers.

Requests for interconnection shall be evaluated to ensure that defined standards of system performance are not violated. The evaluation considers the:

- characteristics of the specific DER requesting interconnection,
- characteristics of the LIPA system at the proposed point of common coupling, and
- aggregate impact of all DER, including DER previously approved for interconnection to the respective system.

LIPA distribution system performance standards, which form the basis of DER interconnection evaluation, are specified In Section 3.

To facilitate DER interconnection evaluation, a series of screens are provided. Proposed DER interconnections passing these screens will be approved for interconnection, subject to all administrative and other non-technical requirements. The first stage of screening (preliminary screening) is intended to expedite approval for DER interconnection requests posing no significant risk that the system performance standards will be violated. The preliminary screening process is described in Section 4. DER interconnection requests not passing the preliminary screens may be subjected to supplemental screening. Supplemental screening, described in Section 5, provides detailed evaluation using a more complex set of criteria. Interconnection requests that do not pass the supplemental screening process are not necessarily denied. At the request of the Applicant, a ~~Comprehensive~~ Coordinated Electrical System Interconnection Review (CESIR) can be performed. A CESIR will consist of one or more detailed technical studies as outlined in Section 6. The scopes of CESIR studies are dependent on the characteristics of the particular interconnection and distribution system, and are defined on a case-by-case basis. The criterion for a CESIR is whether the interconnection will result in violation of the system performance standards defined in Section 3.

Detailed DER interconnection design requirements are specified in Section 7 for DER up to 500 kVA aggregate facility rating, and in Section 8 for DER facilities with ratings exceeding 500 kVA. Commissioning and test requirements are specified in Section 9 and operating requirements are specified in Section 10.

In additional to this document customer interconnecting DER shall also be responsible to meet requirement specified in Specifications & Requirements for Electric installations (Red Book).

The PSEG Long Island Red Book provides general guidelines and specifications for electrical contractors working with PSEG Long Island's electric distribution system.

2. Definitions

Clearing Time - The time between the start of an abnormal condition and the DER ceasing to energize. It is the sum of the detection time, any adjustable time delay, the operating time plus arcing time for any interposing devices (if used), and the operating time plus arcing time for the interrupting device. (Adapted from IEEE 1547)

Coordinated Electric System Interconnection Review (CESIR) - Any studies performed by utilities to ensure that the safety and reliability of the electric grid with respect to the interconnection of distributed energy resources as discussed in this document.

Dedicated transformer - A transformer with a secondary winding that serves only one customer.

Direct transfer trip - Remote operation of a circuit breaker by means of a communication channel.

Disconnect switch - A mechanical device used for isolating a circuit or equipment from a source of power.

DER facility – The collection of all DER equipment, including auxiliary equipment required to comply with the requirements of this document, that are interconnected with the LIPA system at one point.

DER owner: An applicant to operate on-site power generation or electrical energy storage equipment in parallel with the LIPA grid per the requirements of this document.

DER system – The DER generating or energy storage unit plus any auxiliary equipment necessary to meet the requirements of this document or any applicable standard (e.g., protective relays, instrument transformers, capacitor banks, grounding transformers), and any equipment required to interconnect these components to the LIPA point of common coupling (e.g., transformers, circuit breakers, switches, cables, etc.).

Distributed energy resources (DER) - any source of electrical power, including generation and electric energy storage, which are owned by individuals, companies, or agencies, other than PSEG Long Island, within the PSEG LONG ISLAND service area and interconnected to the LIPA distribution system at nominal voltage levels less than 15 kV.

Draw-out type circuit breaker - Circuit breakers that are disconnected by physically separating, or racking, the breaker assembly away from the switchgear bus.

Flicker –repetitive variations in lamp luminance that are perceivable or objectionable to humans.

Feeder section - Portion of a distribution feeder between the primary substation breaker and the first Automatic Sectionalizing Unit (ASU), or between ASUs on a feeder

Grid-Following Inverter – An inverter designed such that the objective of the innermost control loops is to maintain a constant current output that is synchronized with the grid voltage as measured by the inverter. This is the conventional inverter control scheme for the large majority of inverters at this time. These inverters cannot properly and stably operate without some external voltage source with which to synchronize. Therefore, these inverters are intended only for parallel operation with the power grid.

Grid-Forming Inverter – An inverter designed such that a voltage source is provided that is modulated in phase and angle to regulate current or power output only through relatively slow outer control loops. Inverters with this type of control can satisfactorily operate isolated from any other sources, disconnected from the LIPA system, or can synchronize with the grid through relatively slow synchronization algorithms in order to operate in parallel with other sources. Inverters that operate in a grid-forming mode only when disconnected from the LIPA system (e.g., such as for providing a facility backup power source), but operate in the grid following mode when connected to the LIPA system, are not considered to be grid-forming inverters for the purposes of this document but shall be considered to be grid-following inverters.

Islanding - A condition in which a portion of the LIPA System that contains both load and distributed generation is isolated from the remainder of the LIPA System. (Adapted from IEEE 1547.)

Non-integrated control and protection – Control and protection schemes that are not built in to equipment or systems of equipment tested and certified by a Nationally-Recognized Testing Laboratory (NRTL) in accordance with UL 1741, ~~or~~ UL 1741SA, or UL 1741SB.

LIPA system - The electric transmission and distribution system owned by LIPA and operated by PSEG Long Island Electric Utility SERVCO and consisting of all real and personal property, equipment, machinery, tools and materials, and other similar items relating to the transmission and distribution of electricity to PSEG Long Island's customers.

PSEG Long Island - PSEG Long Island LLC, acting through its subsidiary, Long Island Electric Utility Servco LLC.

Point of Common Coupling (PCC) - The point at which the interconnection between the electric utility and the customer interface occurs. Typically, this is the customer side of PSEG Long Island revenue meter.

Point of Interconnection - The point where the Interconnection Facilities connect with LIPA's Distribution System, which shall include the Point of Common Coupling.

Power Control System – A control system intended and designed to regulate power flow across a defined interface, or limit power flow across an interface in either direction to a defined value, by controlling the output of one or more generation ,energy storage, or load devices. A Power Control System (PCS) may regulate the net of any combination of DER output, energy storage input or output and load. PCS are commonly used to limit net power export to zero (non-export for self-consumption) or to an agreed limit to avoid interconnection upgrades.

Rapid voltage change – abrupt, step-wise change in voltage magnitude.

Utility grade relay - A relay that is constructed to comply with, as a minimum, the most current version of the standards listed in Table 1 for non-nuclear facilities.

Table 1 – Standards Applicable to and Defining Utility Grade Relays

Standard	Conditions Covered
ANSI/IEEEC37.90	• Usual service condition ratings • Current and voltage • Maximum design for all relay • AC and DC auxiliary relays • Make and carry ratings for tripping contacts • Tripping contacts duty cycle • Dielectric tests by manufacturer • Dielectric tests by user
ANSI/IEEE C37.90.1	Surge withstand capability (SWC) fast transient test
IEEE C37.90.2	Radio frequency interference
IEEE C37.98	Seismic testing (fragility) of protective and auxiliary relays
ANSI C37.2	Electric power system device function numbers
IEC 255-21-1	Vibration
IEC 2555-22-2	Electrostatic discharge
IEC 25 5-5	Insulation (impulse voltage withstand)

3. Distribution System Performance Standards

This section defines the criteria for acceptable distribution system performance. These are the ultimate criteria for the acceptability of a distributed energy resource (DER) interconnection.

3.1. Applicable System Conditions

Standards stated in this section are applicable to LIPA system conditions inclusive of the following:

a. Normal and n-1 contingency system configurations

b. Any load level between minimum and peak

c. Any level of output from DER that is being evaluated for interconnection

d. Any level of output from DER that has been previously approved for interconnection to the LIPA system.

For solar PV DER, output from the DER will only be considered in conjunction with coincident system load levels.

3.2. Design Basis Events and Contingencies

The system events, contingencies, and disturbances considered for the purposes of evaluating LIPA system performance may include:

a. Concurrent variation in output of all DER connected to the respective distribution system with conservative but reasonable consideration of geospatial diversity in the case of PV DER.

~~a.~~b. Concurrent variation in output of all DER (typically only energy storage) that participate in the NYISO frequency regulation market, either directly for via aggregators.

~~b.~~c. Short-circuit faults of any type (e.g., single phase, three-phase, etc.) and with any fault impedance.

~~c.~~d. Open-circuit faults.

~~d.~~e. Operation of any LIPA system current interruption device with or without the presence of a fault.

~~e.~~f. Spontaneous clearing of any short-circuit fault.

~~f.~~g. Isolation of any LIPA primary distribution substation from its normal source of supply and grounding reference.

3.3. Circuit Capacity

The LIPA distribution system shall be designed to supply the forecast customer load demand without consideration of any offsetting DER capacity, with the exception of any DER that has contracted with LIPA for the provision of firm distribution capacity service.

3.4. Steady-State Voltage

3.4.1. Steady-State Service Voltage Limitations

The steady-state voltage magnitude of any LIPA customer service shall be within ANSI C84.1 Range A (114V – 126V). Temporary deviation of voltage outside of Range A is acceptable until the voltage can be corrected by means such as substation transformer on-load tapchanger action, automatic switching of capacitor banks, and automatic response of DER providing voltage regulation capability. Temporary voltage deviations, other than caused by LIPA system contingencies, shall not result in service voltages outside of ANSI C84.1 Range B. LIPA system contingency conditions shall not result in continuous voltages outside of the appropriate Range C as defined in LIPA DA 55001. Simultaneous tripping of all DER on a feeder or in a distribution system, such as due to a LIPA system fault event initiating required DER undervoltage tripping, shall be considered as a LIPA system contingency for which post-transient voltages shall be within Range C1 regardless of the operating status of any or all DER connected to the LIPA distribution system.

Service voltage at the DER being evaluated may deviate outside of ANSI C84.1 Range A due to the influence of the DER only if the service is supplied via a distribution transformer dedicated solely to the customer requesting DER interconnection, and the customer has reimbursed LIPA for the dedicated transformer. Except for LIPA system contingency conditions, DER service voltages shall not be outside of ANSI C84.1 Range B (110 V – 127V). For primary metered DER customers, voltage at the primary service point (PCC) shall not be outside of ANSI C84.1 Range A. Distribution transformers procured on behalf of DER interconnection applicants shall have off-load taps at +5%, +2.5%, 0%, -2.5%, and -5% of the nominal primary voltage (Note: LIPA Single phase Overhead Transformers do not have taps).

3.4.2. Primary Voltage Range

The steady-state voltage at any location on any LIPA primary distribution feeder, where load is connected, or could be connected in the future, shall not be greater than 1.05 times the nominal voltage nor less than 0.98 times the nominal voltage (Range A, as defined in LIPA DA 55001).

Temporary deviation outside of Range A is acceptable until the voltage can be corrected. Temporary voltage deviations, other than caused by LIPA system contingencies, shall not result in service voltages outside Range B, which is 0.95 – 1.06 times nominal primary voltage. LIPA system contingency conditions shall not result in continuous primary voltages outside of the appropriate Range C as defined in LIPA DA

55001. Simultaneous tripping of all DER on a feeder or in a distribution system, such as due to a LIPA system fault event initiating required DER undervoltage tripping, shall be considered as a LIPA system contingency for which post-transient voltages shall be within Range C1 (0.94 to 1.07 times nominal primary voltage) regardless of the operating status of any or all DER connected to the LIPA distribution system.

3.4.3. Voltage Balance

Phase-to-phase voltages shall be maintained within a 2% balance on primary distribution systems and within 3% on secondary systems.

3.4.4. Pre-Existing Voltages Outside of Range

Where any steady-state voltage or voltage imbalance is outside of the permissible range without the influence of the DER interconnection under evaluation, the DER under evaluation shall not increase or aggravate the deviation of the voltage or voltage imbalance from the acceptable range.

3.4.5. DER Tripping and Reconnection Impact on Voltage

Steady-state voltage limits defined in this section shall apply to at least the following scenarios:

a. Simultaneous tripping of all DER on a distribution system.

b. Simultaneous resumption of operation of all DER on a distribution system. The enter-service power ramping limits or randomized start-up delays (per IEEE Std 1547-2018, Clause 4.10.3) implemented on DER shall be considered in determination of compliance with these voltage limits.

3.5. Power Quality

3.5.1. Voltage Variations

3.5.1.1. Flicker

The aggregate impact of all DER on a distribution system shall not result in flicker more severe than a P_{ST} = 0.9 nor a P_{LT} = 0.9, as defined by IEEE Standard 1453 and LIPA DA 55104, at any customer service with the exception of the service for the DER under evaluation.

Predicted levels of flicker shall be based on a reasonable estimate of the correlation between output variations of all flicker-producing DER on the distribution system

3.5.1.2. Rapid Voltage Change

DER shall not cause the service voltage of any other LIPA customer, or any primary voltage, to experience rapid voltage change greater than the following criteria:

$\Delta V > 5\%$, not acceptable

$3\% < \Delta V \leq 5\%$; not more frequent than 2 times per day (average)

$1.5\% < \Delta V \leq 3\%$; not more frequent than 5 times per day (average) in accordance with DA 55104.

3.5.1.3. Cycling of LIPA Voltage Regulation Equipment

An individual DER interconnection that is inherently subject to uncontrollable active power output variations, including solar PV and wind generation, or to controllable power variations resulting from participation in NYISO frequency regulation ancillary services, shall not cause repeated operation of LIPA tapchangers, step voltage regulators, or switched capacitors due to cyclic variation of the DER output over the full range of its active power output, from zero to rated power.

The aggregate impact of all ~~inherently variable~~such DER on a distribution system shall not cause more than a 10% increase in the average daily number of operations of LIPA tapchangers, step voltage regulators, or switched capacitors. Geospatial diversity of DER output variations may be considered in the prediction of this impact.

3.5.2. Overvoltages

3.5.2.1. RMS Voltage

The root-mean-square magnitude of voltage at any primary- or secondary-level location on the LIPA system, measured from phase to ground and phase-to-phase, shall not exceed the following thresholds and durations:

a. 138% for any RMS voltage measurement period,

b. 120% of nominal for no greater than 0.5 seconds,

c. 115% of nominal for no greater than 1.0 second,

d. 110% of nominal for no greater than 5.0 seconds.

RMS voltage shall be measured over the duration of one fundamental-frequency cycle (0.016666 seconds).

3.5.2.2. Instantaneous Voltage

The cumulative duration of instantaneous voltage (absolute value), over any one-minute period and measured phase to ground and phase to phase, shall not exceed the following thresholds and durations:

a. 180% of nominal peak voltage for any duration,

b. 170% of nominal peak voltage for greater than 1.6 milliseconds,

c. 140% of nominal peak voltage for greater than 3.0 milliseconds,

d. 130% of nominal peak voltage for greater than 16 milliseconds,

e. 120% of nominal peak voltage for greater than 50 milliseconds

f. 110% of nominal peak voltage for greater than 1000 milliseconds.

3.5.3. Harmonics

The LIPA system voltages shall have harmonic components that are limited to the values defined by the current version of IEEE Standard 519.

3.6. Mitigation of Voltage Impacts Using DER Reactive Power Capability

The reactive power injection and absorption capability of DER may be considered as a means of mitigating DER-produced voltage impact. When evaluating a new DER interconnection, the reactive power capability and reactive power regulation means of previously-approved DER shall only be considered if this capability and regulation means is specified in the interconnection agreements of those pre-existing DER interconnections.

3.6.1. Fixed and Scheduled Power Factor Operation

Where reactive power injection or absorption by DER is to be considered, the preferred operating modes are open-loop controls where the reactive power is independent of the voltage at the point of common coupling. Preferred control modes include:

a. Constant power factor (reactive power injection or absorption that is linearly proportional to active power output).

b. Power factor scheduled as a function of time, including time of day or season of year.

c. Power factor or reactive power injection or absorption that is a defined nonlinear function of active power output.

~~3.6.3.~~3.6.2. Closed-Loop Voltage Regulation

Closed-loop voltage regulation by DER, where reactive power injection or absorption are a function of the measured voltage (commonly known as volt-var schemes), have potential for adverse interference or interaction with LIPA distribution system voltage regulation. Where closed loop voltage regulation is to be considered, specific study is necessary to ensure proper voltage regulation coordination. Voltage regulation control settings shall be jointly determined by PSEG Long Island and the DER owner to ensure proper coordination of voltages and regulator action.

~~3.6.4.~~3.6.3. Reactive Power Charges

In general, active power injected into the distribution system by DER results in an increased voltage magnitude. In order to counteract this voltage rise, DER will usually need to absorb reactive power. Because it is necessary for reactive power sources and demands to be balanced in the LIPA system, reactive power absorbed by DER to counteract distribution voltage rise must be replaced by additional reactive resources at the distribution substation or in the transmission system. DER customers may be subject to charges for metered reactive power consumed, including reactive power absorbed for the purpose of mitigating voltage impact caused by the DER.

3.7. Short Circuit Current Contribution

3.7.1. LIPA Equipment Limitations

No individual DER facility, when first interconnected to the LIPA system, shall make an incremental increase in the total short-circuit current magnitude to which any LIPA equipment is exposed that is greater than 20% of the margin between the total short-circuit current prior to the interconnection and the equipment's rated short-circuit current withstand capability.

3.7.2. Protection Coordination

The aggregate short-circuit current of all DER on a distribution system shall not inhibit the ability to apply and coordinate feeder fault protection according to accepted distribution protection practices.

The aggregate ground current contribution of all DER-related ground sources on a distribution system shall not result in ground fault current exceeding 400 A at the supplying LIPA substation.

The aggregate phase current contribution of all DER-related ground sources on a distribution system to a three-phase fault at the supplying LIPA substation shall not exceed 800 A.

3.7.3. Lateral Fuses

The aggregate short-circuit current contribution of all DER interconnected to a fused distribution lateral, in both terms of magnitude and duration, shall neither operate nor damage the lateral fuses for any fault on the main feeder.

3.8. Reclosing Coordination

PSEG Long Island has used an "instantaneous" setting for initial feeder reclosing operations, which in practice results in a faulted feeder being isolated from the LIPA substation for a period of approximately 0.2 to 0.5 seconds. The aggregation of all DER on a distribution feeder using instantaneous reclosing shall not support voltage during an islanded condition greater than 20% of nominal on any phase of the feeder for durations greater than 0.166 seconds.[1]

PSEG-Long Island will consider extending LIPA feeder reclosing delays to 2.5 seconds in order to facilitate DER interconnection with relaxed direct transfer trip requirements. LIPA reclosing relay setting changes and possible replacement of existing reclosing relays that are incompatible with delayed reclosing implementation shall be at the expense of the DER applicant.

3.9. Ground Sources

Interconnection of ground sources to LIPA distribution feeders is to be avoided. Where ground sources must be applied to achieve the overvoltage performance specified in Section 3.5.2, the minimum necessary zero-sequence admittance will be used. Ground sources shall not interfere with coordination of feeder protection including ground fault protection.

[1] Autonomous "anti-islanding" functions, which are included in DER certified according to UL-1741, are not tested for this rapidity of detection. Therefore, these functions are not considered in determining compliance with this requirement.

4. Preliminary DER Interconnection Screening

Preliminary screening applies simple criteria intended to identify, with limited effort, DER interconnection requests that clearly have no significant risk of causing individually, or in conjunction with other previously approved DER interconnections, violations of the LIPA system performance criteria defined in Section 00~~3~~.

The preliminary screens are limited in application to DER that are interfaced to the LIPA system via current-regulated utility-interactive inverters. Interconnection applications employing other technologies, including synchronous generators, induction generators, ~~and~~ doubly-fed generators, and grid-forming inverters are not ~~suitably~~ completely screened for significant LIPA system impacts by these criteria and are thus referred to the supplemental screening process for evaluation. However, these non-inverter DER shall also be subjected to the preliminary screening tests defined in this section as part of the supplemental screening process.

The preliminary screens for inverter-interfaced DER are as follows:

Screen P1 – Is interconnection to a secondary area or spot network or interconnection to a primary feeder that also supplies one or more secondary network proposed?

- Yes – Fail, interconnection to LIPA secondary area network is not permitted. If interconnection to a spot network or to a primary feeder serving a secondary spot or area network is proposed, a CESIR must be performed.
- No – Continue to Screen P2.

Screen P2 – Does the DER facility, including any of its transformers or generation equipment, present a ground source to the LIPA system having zero sequence admittance greater than 1.0 per unit on the bases of the LIPA system nominal voltage and the facility's rated kVA (the greater of the peak load kVA and the aggregate generation nameplate kVA rating).[2]

- Yes – Fail, applicant can opt for a CESIR. Supplemental screening is not appropriate for failure of this screen.
- No – Continue to Screen P3.

[2] See Appendix C for information regarding ground sources.

Screen P3 – Does rated kVA of DER (and in the case of energy storage DER, does the maximum charging power plus the maximum load demand) exceed the rating of the secondary service cable or the service transformer? (If a UL-certified Power Control System is applied, does the power limit maintained by the Power Control System exceed the rating of the secondary service cable or the service transformer?)

- Yes – Fail, supplemental screening or CESIR are not appropriate for failure of this screen. The applicant may make arrangements for appropriate upgrade of service, and the screening process may then resume with Screen P4.
- No – Continue to Screen P4.

Screen P4 – Will the proposed DER meet the requirements of IEEE 1547-2018, Clause 4.2, for the Reference Point of Applicability to be at the DER unit Point of Connection (DER unit terminals)?

- Yes – Continue to Screen P5.
- No – The DER design shall be subject to a CESIR (Detailed Design Review), as specified in IEEE 1547.1-2020. The requirement for this review notwithstanding, screening may continue with Screen P6.

Screen P5 – ~~Is certified~~Does all power ~~-equipment~~injecting equipment consist of inverters certified to UL Standard 1741 Supplements A or B~~to be used~~?

- Yes – Continue to Screen P6.
- No – The DER design shall be subject to a CESIR (Detailed Design Review), as specified in IEEE 1547.1-2020, as part of the CESIR process. The requirement for this review notwithstanding, screening may continue with Screen P6.

Screen P6– Does the DER Equivalent ~~penetration~~ Penetration ~~ratio~~Ratio[3], including the DER under review, of the distribution system served by a distribution substation bus exceed 80%?

- Yes – Fail, requester can opt for a CESIR. Supplemental screening is not appropriate for failure of this screen.
- No - Continue to Screen P7

[3] Refer to Appendix A for methodology of determining penetration, including when DER contribution affects historic loading data. For this specific screen, existing DER is not excluded from the determination of penetration. Note that the Equivalent Penetration Ratio definition has rotating generator capacity scaled by a factor of six to account for the stiffness of these sources.

Screen P7 – Will the proposed interconnection use three-phase ~~inverters~~ DER units or a reasonably balanced array of single-phase ~~inverters~~DER units[4]?

- Yes – Continue to Screen P8

- No - Fail, applicant can opt for a CESIR. Supplemental screening is not appropriate for failure of this screen.

Screen P8 – Is the interconnection to a primary lateral longer than 1000' that also serves other customers?

- Yes – Fail, applicant can opt for a CESIR. The supplemental screening process does not accommodate long lateral situations.

- No - Applications for DER connected directly to a main feeder, a lateral shorter than 1000', or via a dedicated lateral, can continue to Screen P9.

Screen P9 – Is the DER penetration ratio[5] on the feeder greater than 70%?

- Yes – Fail, applicant can opt for supplemental screening. The supplemental screening process is to be entered at Screen S1. (Note, if penetration exceeds 85%, project will need to go directly to CESIR.)

- No. - ~~-~~Continue to Screen P10

Screen P10 – Is the DER Equivalent Penetration Ratio[6] on the feeder greater than 50% and the feeder breaker and any upstream automatic circuit recloser reclosing delay is set to less than 2.5 seconds?

- Yes – Fail, DTT is required or applicant can opt to accept responsibility for costs to implement an alternative means to avoid out-of-phase reclosing including extension of reclosing delay (which may entail relay replacement). Preliminary screening may continue to Screen P11 with this provision.

- No. - ~~-~~Continue to Screen P11

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[4] Reasonable balance is defined as the single phase ~~inverter~~ DER unit capacity shall be within ±10% of the average per-phase capacity for all phases and the energy resources for the inverters on each phase are similar.

[5] Refer to Appendix A for methodology of determining penetration, including when DER contribution affects historic loading data. For this specific screen, existing DER with DTT is not excluded from the determination of penetration. Note that this is not the "effective" penetration ratio as used in Screen P6.

[6] Refer to Appendix A for methodology of determining penetration, including when DER contribution affects historic loading data. For this specific screen, existing DER with DTT is excluded from the determination of penetration.~~.~~ Note that the ~~effective~~equivalent penetration ratio definition has rotating generator capacity scaled by a factor of six to account for the stiffness of these sources.

Screen P11 – Is there greater than 20% penetration, relative to absolute minimum feeder load, of synchronous generator DER not having direct transfer trip implemented, inclusive of the proposed, previously approved, and existing DER?

- Yes – Fail, DTT or other mitigation must be applied.
- No - Continue to Screen P12

Screen P12 – Does the total DER penetration on the primary substation bus exceed 25% of the substation transformer rating, or does the penetration of energy storage on the primary substation bus, that participates or may participate in the frequency regulation ancillary services market, exceed 10% of the substation transformer rating?

- Yes – Fail, applicant can opt for supplemental screening.
- No – Continue to Screen P13.

Screen P13- Is the interconnection via a distribution transformer dedicated to the applicant's facility?

- Yes – Preliminary screening is successfully completed.
- No – Fail, applicant can opt for supplemental screening. The supplemental screening process is to be entered at Screen S12. Alternatively, the applicant may make arrangements for provision of dedicated transformer, and the preliminary screening process shall then be complete.

5. Supplemental Interconnection Screens

For inverter-interfaced DER interconnection applications that do not pass certain preliminary screens, or for rotating generator DER interconnection applications (which are not completely covered by the preliminary screening process), applicants may opt for the supplemental screening process. Supplemental DER screens are criteria that identify if the proposed DER interconnection will result in violation of LIPA system performance criteria using more detailed information regarding the DER characteristics and the characteristics of the LIPA system at the point of proposed interconnection. The supplemental criteria are intended to be applicable without detailed engineering analysis.

Screen S1 – Can steady-state voltages on the primary feeder under normal conditions result in voltages at any other customer services greater than the upper limit of ANSI C84.1 Range A? (Refer to Appendix B-1 for the calculation on which this supplemental screen is based.)

- Yes – Fail, applicant may opt for a CESIR to provide a more refined analysis.
- No – Continue to Screen S2.

Screen S2– Can steady-state voltages on the primary feeder under normal conditions result in voltages at any other customer services less than the lower limit of ANSI C84.1 Range A? (Refer to Appendix B-2 for the calculation on which this supplemental screen is based.)

- Yes – Fail, applicant may opt for a CESIR to provide a more refined analysis.
- No – Continue to Screen S3.

Screen S3 – If the DER being screened is inherently variable in output (e.g., PV), can the repetitive voltage variation due to the aggregate impact of all variable DER on the feeder exceed 2%? (Refer to Appendix B-3 for the calculation on which this supplemental screen is based.)

- Yes – Fail, applicant may opt for a CESIR to make a more refined analysis.
- No, or the DER is not inherently variable – Continue to Screen S4.

Screen S4 – If the DER being screened is inherently variable in output, can the repetitive real and reactive current variations due to the aggregate impact of all variable DER on the distribution system served by the primary substation bus result in excessive operation of the primary substation's on-load tap changer? (Refer to Appendix B-4 for the calculation on which this supplemental screen is based.)

- Yes – Fail, applicant may opt for a CESIR to make a more refined analysis.
- No, or the DER is not inherently variable – Continue to Screen S5.

Screen S5 – Can simultaneous tripping of all DER on the distribution system result in any customer service voltages being less than the lower limit of ANSI C84.1 Range B? (Refer to Appendix B-5 for the calculation on which this supplemental screen is based.)

- Yes – Fail, applicant may opt for a CESIR to make a more refined analysis.
- No – Continue to Screen S6.

Screen S6 – Can return to service of all DER on the distribution system result in any customer service voltages exceeding the upper limit of ANSI C84.1 Range B? (Refer to Appendix B-6 for the calculation on which this supplemental screen is based.)

- Yes – Fail, applicant may opt for a CESIR to make a more refined analysis.
- No – Continue to Screen S7.

Screen S7 – Can the aggregate current injection by all DER on the distribution system result in fault currents exceeding the ratings of any LIPA equipment? (Refer to Appendix B-7 for the calculation on which this supplemental screen is based.)

- Yes – Fail, applicant may opt for a CESIR to make a more refined analysis.
- No – Continue to Screen S8.

Screen S8 – Can the aggregate impact of all DER result in excessive load-rejection overvoltage? (Refer to Appendix B-8 for the calculation on which this supplemental screen is based.)

- Yes – Fail, interconnection is denied.
- No – Continue to Screen S9.

Screen S9 – Can the aggregate impact of all DER result in excessive ground-fault overvoltage? (Refer to Appendix B-9 for the calculation on which this supplemental screen is based.)

- Yes – Fail, applicant may opt for a CESIR to make a more refined analysis.
- No – Continue to Screen S10.

Screen S10 – Is the interconnection potentially disruptive to protection coordination? (Refer to Appendix B-10 for the calculation on which this supplemental screen is based.)

- Yes – Fail, applicant may opt for a CESIR to make a more refined analysis or to determine necessary system protection modifications.
- No – Continue to Screen S11.

Screen S11 – Is the interconnection via a distribution transformer dedicated to the applicant's facility?

- Yes – Supplemental screening is successfully completed.
- No – Continue to Screen S12.

Screen S12 – Is the location of the service transformer on the feeder such that the service voltage provided to other customers sharing the same distribution transformer are less than the upper limit of ANSI C84.1 Range A? (Refer to Appendix B-11 for the calculation on which this supplemental screen is based.)

- Yes – Supplemental screening is successfully completed.
- No – Fail, applicant may arrange for a dedicated transformer or may opt for a CESIR to make a more refined analysis.

~~7.~~6. Coordinated Electric System Interconnection Review (CESIR)

DER interconnection applications that do not pass the supplemental screening process may, at the discretion of the applicant, be subjected to a Coordinated Electric System Interconnection Review (CESIR). A CESIR is a detailed engineering study and often requires system simulation and modeling.

~~8.~~7. Interconnection Design Requirements – DER ≤ 500 kVA

The requirements stated in this section apply to DER facilities having an aggregate nameplate rating of 500 kVA or less. All LIPA criteria for DER interconnection, unless otherwise specified, are based on the aggregate nameplate rating of all DER connected to a single point of common coupling with the LIPA system. Unless explicitly stated, ratings are the gross generation capability and are not net of load demand.

All DER interconnecting with the LIPA system shall be compliant with the version of IEEE Std 1547 (including any amendments) current at the time of interconnection application). The DER owner shall additionally be responsible for ongoing compliance with all applicable local, state, and federal codes, including all applicable sections of the NEC, and standardized interconnection requirements set forth herein, as they pertain to the interconnection of the DER equipment.

This Section defines specific DER equipment and technical interconnection requirements that are in addition to, modify, or further define those specified in IEEE-1547.

Unless otherwise specified or restricted by this document, the specific design of the DER interconnection, including protection, control and grounding schemes, is the responsibility of the DER owner. The appropriate design may depend on the size and characteristics of the DER, the DER owner's load level, and the characteristics of the particular portion of LIPA's system where the DER owner is interconnecting. PSEG Long Island reserves the right to impose site-specific interconnection requirements on a case by case basis.

~~8.1.~~7.1. General DER Interconnection Requirements

~~8.1.1.~~7.1.1. Certification of Equipment

In order for the equipment to be acceptable for interconnection to the LIPA System, the DER interface equipment must be tested by a Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration (OSHA) in compliance with Underwriter's Laboratories (UL) 1741, 1741SA, or 1741SB, Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources.

Any Power Control System (PCS) applied to limit DER facility power export or import limits used as the basis for interconnection review shall be certified to UL 1741 Certification Requirement Decision for Power Control Systems.

For each interconnection application, documentation including the proposed equipment certification, stating compliance with UL 1741 by an NRTL, shall be provided by the applicant to PSEG Long Island. Supporting information from the Public Service Commission's website (http://www.dps.state.ny.us/distgen.htm), an NRTL website or UL's website stating compliance is acceptable for documentation.

PSEG Long Island is not responsible for reviewing and approving equipment tested and certified by a non- NRTL.

If equipment is UL 1741, UL 1741SA, or UL 1741 SB certified by an NRTL and compliance documentation is submitted to PSEG Long Island, PSEG Long Island shall accept such equipment for interconnection in New York State. All equipment certified to UL 1741, UL1741SA, or UL 1741SB by an NRTL shall be deemed “certified equipment” even if it does not appear on the Public Service Commission’s website.

Utility Grade Relays need not be certified per the requirements of this section.

After ~~January~~ January 1, ~~2022~~2023, only certification to UL 1741SB shall be accepted for new interconnection applications.

~~8.1.2.~~7.1.2. Distribution System Configuration Restrictions

DER systems may only interconnect directly to the LIPA distribution system through a line designed for radial operation.

Interconnections shall not be made to secondary area network systems. Interconnection to secondary spot networks or primary feeders supplying area or spot networks may be permitted only where studies indicate adverse operation of network protectors will not result.

PSEG Long Island will evaluate applications for interconnections to looped radial primary systems (fused loops). If approved, these interconnections shall be made through a LIPA installed and owned fused disconnect switch installed on the primary side of the customer owned transformer. The installation of the fused switch shall be at the DER owner’s expense.

~~8.1.3.~~7.1.3. Revenue Metering

The customer shall be Secondary or Primary Metered as defined by PSEG Long Island’s tariffs for DER system less than 500 kVA. The requirement for secondary metering and primary metering are defined in Specifications & Requirements for Electric installations (Red Book). Additional Primary Metering requirements are defined on PSEG Long Island Construction Standard CS-8735 “Typical 15kV Primary Instrument Transformer Cubicle and CS-8736 “Typical 5kV Primary Instrument Transformer Cubicle”.

~~8.2.~~7.2. Utility Disconnect Switch/Isolation

All DER equipment with rating greater than 25 kW and systems of 25 kW or less that are capable of operation when isolated from a synchronous source (inclusive of, but not limited to synchronous generators and grid-forming inverters) shall be capable of being isolated from the LIPA System by means of an external, manual, visible, gang-operated, lockable, load break disconnecting switch. The disconnect switch shall be installed, owned, and maintained by the

DER owner, and located electrically between the DER equipment and its interconnection point with the LIPA System.

The disconnect switch must be rated for the voltage and current requirements of the installation. The basic insulation level (BIL) of the disconnect switch shall be such that it will coordinate with that of LIPA's equipment. Disconnect devices shall meet applicable UL, ANSI, and IEEE standards, and shall be installed to meet all applicable local, state, and federal codes. (Applicable Local City Building Code may require additional certification.)

The disconnect switch shall be readily accessible to PSEG Long Island at all times and physically located such that it is within 10 feet of the PSEG Long Island metering point or within 10 feet of the LIPA service entrance. The disconnect switch must be lockable in the open position with a 3/8" shank LIPA padlock. If such location is not possible, the DER owner will propose, and PSEG Long Island will approve, an alternate location. The disconnect switch shall be clearly marked, "Generator Disconnect Switch," (the same wording shall also be used for electrical energy storage DER) with permanent 3/8 inch or larger letters or larger. The DER owner shall provide a ground and test device acceptable to PSEG Long Island.

If an interconnection breaker of the draw out type is used and the DER owner provides a ground and test device acceptable to PSEG Long Island, PSEG Long Island may evaluate waiving the isolation disconnect switch requirement.

~~8.3.~~7.3. Interconnection Transformer

~~8.3.1.~~7.3.1. Dedicated Interconnection Transformer

PSEG Long Island reserves the right to require a DER facility to connect to the LIPA System through a dedicated transformer for secondary metering service. The transformer shall be provided by PSEG Long Island at the DER owner's expense; purchased from PSEG Long Island~~,~~ or purchased by the DER owner with conformance to PSEG Long Island's specifications. The transformer may be necessary to ensure conformance with PSEG Long Island safe work practices, to enhance service restoration operations or to prevent detrimental effects to other PSEG Long Island customers. The transformer that is part of the normal electrical service connection of a DER owner's facility may meet this requirement if there are no other customers supplied from it. A dedicated transformer is not required if the installation is designed and coordinated with PSEG Long Island to protect the LIPA System and its customers adequately from potential detrimental net effects caused by the operation of the DER.

If PSEG Long Island determines a need for a dedicated transformer, it shall notify the DER owner in writing of the requirements. The notice shall include a description of the specific aspects of the LIPA System ~~-~~that necessitate the addition, the conditions under which the dedicated transformer is expected to enhance safety or prevent detrimental effects, and the expected response of a normal, shared transformer installation to such conditions. The transformer will be a standard LIPA transformer as listed in DA 50005. If a non- LIPA configuration transformer is required for the interconnection, it shall be procured, installed and owned by the customer. The customer shall be responsible to maintain any spare units.

~~8.3.3.~~7.3.2. Existing Transformer

The ownership of an existing LIPA transformer cannot be transferred to customer if customer becomes a new primary metered installation. The DER owner will bear the cost of removal of existing LIPA transformer and installation of new customer owned transformer.

~~8.4.~~7.4. Ride-Through Capability

DER connecting to the LIPA system shall, at a minimum, have voltage and frequency disturbance ride-through capabilities in accordance with IEEE 1547 with the following performance category assignments:

a. Synchronous and induction generator DER shall meet the ride-through requirements specified for Performance Category I.

b. Photovoltaic or battery energy storage DER shall meet or exceed the ride-through requirements specified for Performance Category III.

c. All other inverter-based DER shall meet or exceed the ride-through requirements specified for Performance Category II.

~~8.5.~~7.5. Interconnection Control and Protection Requirements

Stated below are the standard protection and control requirements applicable to DER interconnections to the LIPA system, rated 500 kVA or less, that are in addition to those specified by IEEE Std 1547.

In addition to the requirements specified here, PSEG Long Island may require additional protective functions (such as DTT) and/or utility grade relays on a case-by-case basis. If PSEG Long Island determines a need for additional functions, it shall notify the DER owner in writing of the requirements. The notice shall include a description of the specific aspects of LIPA's system that necessitate the addition, and an explicit justification for the necessity of the enhanced capability. Requirements in Section 8 shall be followed for any additional protective functions and/or utility grade relays that are required by PSEG Long Island.

No protective equipment specified by PSEG Long Island or required by IEEE 1547, shall be changed or modified at any time without the written consent of PSEG Long Island.

~~8.5.1.~~7.5.1. Interrupting Device

The DER owner shall provide appropriate protection and control equipment, including an interrupting device(s) sized to meet all applicable local, state and federal codes, that will isolate and protect the LIPA system for a fault in the DER facility.

~~8.5.2.~~7.5.2. Voltage Trip Settings

Under- and over-voltage trip functions, as specified in IEEE 1547, shall be set with the following thresholds and such as to achieve the following clearing times (The clearing time is the time between the start of the abnormal condition and the DER System ceasing to energize the LIPA system - interrupting device operating time plus relay time):

For DER assigned to ride-through performance Categories I and II by Section 7.4 of this document

Voltage Range (% of base voltage)	Clearing Time (seconds)	Clearing Time (cycles)
V ≤ 50	0.16	9.6
V ≤ 88	5.0	300
V ≥ 110	1.0	60
V ≥ 120	0.16	9.6

For DER assigned to ride-through performance Category III by Section 7.4 of this document

Voltage Range (% of base voltage)	Clearing Time (seconds)	Clearing Time (cycles)
V ≤ 50*	1.1	66
V ≤ 88	5.0	300
V ≥ 110*	2.0	120
V ≥ 120	0.16	9.6

*Category III DER shall cease current injection to the LIPA system ("momentary cessation" as defined by IEEE 1547-2018) within 0.083 seconds (5 cycles) for voltage less than 50% or voltage greater than 110%.

For three-phase DER facilities where all transformers between the LIPA primary voltage level and the location of DER voltage sensing are not connected grounded-wye/grounded-wye, a protection study will be conducted by PSEG Long Island to determine the protection requirements.

The nominal primary line to line voltages on the LIPA distribution system are 13.2 kV and 4.16 kV, and nominal secondary voltages are 120/240 V (single phase), 208Y/120 and 480Y/277 V (three phase). Base voltages specified above are the nominal LIPA system voltages for the relevant Reference Point of Applicability as defined in IEEE 1547.

~~8.5.3.~~7.5. 3. Frequency Trip Settings

Under- and over-frequency trip functions, as specified in IEEE 1547, shall be set with the following thresholds and such as to achieve the following clearing times (The clearing time is the time between the start of the abnormal condition and the DER

System ceasing to energize the LIPA system - interrupting device operating time plus relay time):

Frequency Range (Hz)	**Clearing Time (seconds)**	**Clearing Time (cycles)**
f ≤ 56.5*	0.16	9.6
f ≤ 58.~~0~~5*	~~180~~300	~~10800~~18000
f ≥ 61.~~0~~2	~~180~~300	~~10800~~18000
f ≥ 62.0	0.16	9.6

* The under frequency setting is a recommended setting based on NERC standard PRC-006-NPCC-1 Automatic Under frequency Load Shedding curve Figure 1.

~~8.5.4.~~7.5.4. Faults on DER Owner's System

The DER owner's protection system shall detect any faults within the DER Owner's system and shall interrupt the current contribution from the LIPA system to any such fault.

~~8.5.5.~~7.5.5. Protection of DER Equipment

Responsibility for protection of the DER system and its equipment against possible damage resulting from parallel operation with the LIPA distribution system lies solely with the DER owner.

LIPA transmission lines have automatic instantaneous reclosing and distribution feeders have either automatic instantaneous or time delay reclosing with a dead time as short as 12 cycles and as long as 30 seconds. It is the DER system owner's responsibility to protect its equipment from being reconnected out-of-synchronism with the LIPA system after automatic reclosing of a LIPA circuit breaker.

Where direct transfer trip (DTT) is used or required, it is solely for protection of the LIPA system. Neither PSEG Long Island nor LIPA warrant that the DTT system will be absolutely effective in preventing out-of-synchronism reclosing of the distribution circuit to which the DER is connected.

Implementation of DER protection shall not interfere with or degrade any performance required in this document or in any applicable standard, including the latest version of IEEE 1547.

~~8.5.6.~~7.5.6. Synchronization Facilities

Synchronizing facilities shall be required for any DER using synchronous generators, grid-forming inverters, or where the Owner's system is capable of operation in isolation from the LIPA system (microgrid). Synchronizing facilities shall either consist of automatic synchronizing equipment or the means to perform manual synchronization. Automatic synchronizing equipment shall be optional.

Synch check relays are required across the interconnection breaker of a synchronous generator or microgrid unless otherwise specified. The existence of automatic synchronization equipment does not eliminate the requirement for a synch check relay. A total of four potential transformers shall be required, three on LIPA's side of the breaker and one on the DER side.

~~8.5.7.~~7.5.7. Coordination with Reclosing

"Instantaneous" reclosing is implemented as a standard practice on LIPA overhead distribution feeders, except where modifications have been made to implement delayed reclosing. Out-of-phase reclosing of LIPA feeders significantly energized in an islanded state by DER can be damaging to LIPA system equipment, the equipment of other customers, and to the operating DER.

Where the DER interconnected to a feeder reaches sufficient aggregate capacity to sustain voltage greater than 20% of nominal during an islanding condition, and the feeder uses a reclosing delay less than 2.5 seconds, all additional DER capacity interconnected to that feeder shall be interconnected only on the condition that means are implemented to discontinue participation of these DER in sustenance of any island prior to LIPA circuit reclosing. DER anti-island technology, tested to meet a two-second island detection time per IEEE 1547.1, is not considered sufficient to comply with this requirement except where LIPA feeder reclosing delays have been extended to 2.5 seconds or greater

The need for protection schemes to eliminate islands prior to circuit reclosing are related to the aggregate DER capacity on a LIPA distribution circuit section, circuit loading, and the types of DER interconnected. Protection system requirements shall be determined during the interconnection screening process or in a CESIR.

For DER interconnections to feeders with less than 2.5 second reclosing delays, mitigating measures may include direct transfer trip (DTT), and hot line blocking. For inverter based systems, increasing LIPA feeder reclosing delay to 2.5 seconds would eliminate the need for mitigating measures but the DER owner is responsible for all associated costs.

LIPA distribution systems are reconfigured to restore service following outages, facilitate maintenance, and to alleviate overloads. If the feeder section to which a DER is connected is reconfigured to be fed from an alternate source, the alternate source may not have delayed reclosing or hot-line blocking implemented. Therefore, it may be necessary to require DER to shut down for the duration of reconfigured operation.

For customer facilities which are fed from the load side of a LIPA owned Automatic Throwover Switch (ATO), DERs are not permitted to interconnect on the load side of the ATO. The DER owner may request that PSEG Long Island investigate viable options to allow the DER to interconnect on the load side of this LIPA owned ATO. Some viable options may require – LIPA ATO to be reprogrammed to manual mode, customer DER to disable automatic reclosing (re-entry to service) of their DER system and coordination of switching and manual reclosing/re-entry with the PSEG Long Island Distribution System Operator. Note that PSEG Long Island will not provide any status signals from the LIPA owned ATO to the DER owner to be used in any protection or control scheme.

~~8.5.8.~~7.5.8. Re-Entry to Service

Re-entry of the DER to service~~,~~ following any protective trips[7]~~,~~ shall be delayed until the LIPA system voltage and frequency have recovered and continuously remain within the following criteria for 300 s:

0.9 PU < Voltage < 1.05 PU

59.3 Hz < Frequency < 60.5 Hz

PSEG Long Island, at its discretion, may require the DER Operating Instructions to prohibit automatic re-entry to service, with re-entry to service only by specific permission of the PSEG Long Island Distribution System Operator.

~~8.5.9.~~7.5.9. Direct Transfer Trip (DTT)

DTT may be required (at the DER owner's expense) if it is determined that conditions exist that could jeopardize the reliability and security of the LIPA system. The loading of the distribution circuit and the amount of existing or proposed DER on the distribution circuit may also influence if DTT is required. If DTT is required, the requirements in Section 8.5.6 shall apply to the design of the DTT system.

~~8.5.10.~~7.5.10. Supervisory Control and Data Acquisition (SCADA)

For DER equal to 500KVA SCADA is required (see design requirements in Section 8.5.7~~8.5.7~~~~8.5.7~~). For DER less than 500KVA SCADA may be required if it is determined that conditions exist that could jeopardize the reliability of the LIPA system. ~~If SCADA is required, the requirements in Section 8.5.7 shall apply to the design of the SCADA system.~~

~~8.6.~~7.6. Induction Generator Starting

DER systems utilizing induction generation may be connected and brought up to near-synchronous speed (as an induction motor) if it can be demonstrated that the initial voltage drop measured at the PCC is acceptable based on current inrush limits. The same requirements also apply to induction generation connected at or near synchronous speed because a voltage dip is present due to an inrush of magnetizing current. The DER owner shall submit the expected number of starts per specific time period and maximum starting kVA draw and power factor data to PSEG Long Island.

~~8.7.~~7.7. Reactive Power

DER shall have reactive power capability at the Reference Point of Applicability as defined in IEEE 1547. Inverter-based DER shall comply in accordance with Category B and all other types

[7] "Trip" is not inclusive of momentary cessation required of Category III DER per IEEE 1547-2018.

of generation shall comply with Category A requirements for reactive power capability specified in IEEE 1547.

DER shall be operated at unity power factor unless otherwise specified by PSEG Long Island. Implementation of any of the reactive power control modes specified by IEEE 1547, and any related control parameters, may be required at any time by PSEG Long Island. Any required changes to control mode or parameters shall be implemented by the DER Owner, at their expense, within 30 days of notification by PSEG Long Island.

Flow of reactive power through the DER facility's metering point is subject to the appropriate PSEG Long Island tariff.

~~8.8.~~7.8. DER Drawing and Documentation Requirements

The DER owner shall submit the following interconnection design documentation, in addition to the information provided on the application forms, for review and comment by PSEG Long Island. Example drawings are in ~~appendix~~ Appendix D which may be accessed at the PSEG Long Island website.

~~8.8.1.~~7.8.1. Inverter-Based DER Documentation Requirements

a. DER system interconnection one-line drawing that includes the following information:

   i. Single line representation of the DER system interconnecting to the LIPA system.

   ii. LIPA feeder ID, switches, breakers, fuses, transformers and generation source.

   iii. Name, model number and description of major equipment

   iv. Fuse ratings (Make, Model, and Time Curve Characteristic), CT ratios, CT accuracy class, PT ratios and connections of CTs and PTs

   v. Relay protection scheme if protective relays are used. Show tripping from protection devices to interrupting device. ANSI designations shall be used to describe all protective relay functions.

   vi. Transformer rating, positive sequence impedance, winding configuration and connected voltages.

   vii. Maximum inverter current contribution to a short circuit

   viii. Line of demarcation between LIPA equipment and developer's equipment.

ix. Protective functions and settings of the integrated control and protection package must be tabulated and depicted on the one-line diagram.

b. Instruction manual for inverters

~~8.8.2.~~7.8.2. Synchronous Generator Documentation Requirements

a. DER system interconnection one-line drawing that includes the following information:

   i. Single line representation of the DER system interconnecting to the LIPA system.

   ii. LIPA feeder ID, switches, breakers, fuses, transformers and generation source.

   iii. Name, model number and description of major equipment

   iv. Fuse ratings (Make, Model, and Time Curve Characteristic), CT ratios, CT accuracy class, PT ratios, and connections of CTs and PTs. Identify where synch check function is being performed.

   v. Relay protection scheme if protective relays are used. Show tripping from protection devices to interrupting device. ANSI designations shall be used to describe all protective relay functions.

   vi. DER self-protection scheme

   vii. Transformer rating, positive sequence impedance, winding configuration and connected voltages.

   viii. Generator rating, positive sequence impedance, negative sequence impedance, zero sequence impedance,

   ix. Generator grounding and generator protection scheme.

   x. Line of demarcation between LIPA equipment and developer's equipment.

   xi. Protective functions and settings of the integrated control and protection package must be tabulated and depicted on the one-line diagram.

~~8.8.3.~~7.8.3. Induction Generator Documentation Requirements

a. DER system interconnection one-line drawing that includes the following information:

   i. Single line representation of the DER system interconnecting to the LIPA system.

   ii. LIPA feeder ID, switches, breakers, fuses, transformers and generation source.

iii. Name, model number and description of major equipment

iv. Fuse ratings (Make, Model, and Time Curve Characteristic), CT ratios, CT accuracy class, PT ratios, and connections of CTs and PTs. Identify where synch check function is being performed.

v. Relay protection scheme if protective relays are used. Show tripping from protection devices to interrupting device. ANSI designations shall be used to describe all protective relay functions.

vi. DER self-protection scheme

vii. Transformer rating, positive sequence impedance, winding configuration and connected voltages.

viii. Generator rating, positive sequence impedance, negative sequence impedance, zero sequence impedance,

ix. Generator grounding and generator protection scheme.

x. Line of demarcation between LIPA equipment and developer's equipment.

xi. Protective functions and settings of the integrated control and protection package must be tabulated and depicted on the one-line diagram.

~~9.~~8. Interconnection Design Requirements – DER > 500 kVA

The requirements stated in this section apply to DER facilities having an aggregate nameplate rating of greater than 500 kVA. All LIPA criteria for DER interconnection, unless otherwise specified, are based on the aggregate nameplate rating of all DER connected to a single point of common coupling with the LIPA system. Unless explicitly stated, ratings are the gross generation capability and are not net of load demand.

All DER interconnecting with the LIPA system shall be compliant with the version of IEEE Std 1547 (including any amendments) current at the time of interconnection application. The DER owner shall additionally be responsible for ongoing compliance with all applicable local, state, and federal codes, including all applicable sections of the NEC, and standardized interconnection requirements set forth herein, as they pertain to the interconnection of the DER equipment. Additionally, the DER system shall meet PSEG Long Island's Specifications and Requirements for Electric Installations (Red Book).

This Section defines specific DER equipment and technical interconnection requirements that are in addition to, modify, or further define those specified in IEEE-1547.

Unless otherwise specified or restricted by this document, the specific design of the DER interconnection, including protection, control and grounding schemes, is the responsibility of the DER owner. The appropriate design may depend on the size and characteristics of the DER, the DER owner's load level, and the characteristics of the particular portion of LIPA's system where the DER owner is interconnecting. PSEG Long Island reserves the right to impose site-specific interconnection requirements on a case by case basis.

~~9.1.~~8.1. General DER Interconnection Requirements

~~9.1.1.~~8.1.1. Certification of Equipment

In order for the equipment to be acceptable for interconnection to the LIPA System, the DER interface equipment must be tested by a Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration (OSHA) in compliance with Underwriter's Laboratories (UL) 1741, 1741SA, or 1741 SB Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources.

Any Power Control System (PCS) applied to limit DER facility power export or import limits used as the basis for interconnection review shall be certified to UL 1741 Certification Requirement Decision for Power Control Systems.

For each interconnection application, documentation including the proposed equipment certification, stating compliance with UL 1741 by an NRTL, shall be provided by the applicant to PSEG Long Island. Supporting information from the Public Service Commission's website (http://www.dps.state.ny.us/distgen.htm), an NRTL website or UL's website stating compliance is acceptable for documentation.

PSEG Long Island is not responsible for reviewing and approving equipment tested and certified by a non- NRTL.

If equipment is UL 1741, UL 1741SA, or UL 1741SB certified by NRTL and compliance documentation is submitted to PSEG Long Island, PSEG Long Island shall accept such equipment for interconnection in New York State. All equipment certified to UL 1741, UL1741SA, or UL1741SB by an NRTL shall be deemed “certified equipment” even if it does not appear on the Public Service Commission’s website.

After ~~January~~ January 1, ~~2022~~2023, only certification to UL 1741SB shall be accepted for new interconnection applications.

Utility Grade Relays need not be certified per the requirements of this section but shall be acceptable to and approved by PSEG Long Island.

~~9.1.2.~~8.1.2. Distribution System Configuration Restrictions

DER systems may only interconnect directly to the LIPA distribution system through a line designed for radial operation. Interconnections shall not be made to secondary area network. Interconnection to secondary spot networks or to primary feeders supplying area or spot networks may be permitted only where studies indicate adverse operation of network protectors will not result.

PSEG Long Island will evaluate applications for interconnections to looped radial primary systems (fused loops). If approved, these interconnections shall be made through a LIPA installed and owned fused disconnect switch installed on the primary side of the customer owned transformer. The installation of the fused switch shall be at the DER owner’s expense.

~~9.1.3.~~8.1.3. Revenue Metering

The customer shall be Primary Metered as defined by PSEG Long Island’s tariffs for DER system greater than 500 kVA. Secondary Meter for DG system greater than 500 kVA will be permitted up to 1 MVA on a case by case basis only. The requirement for secondary metering and primary metering are defined in Specifications & Requirements for Electric installations (Red Book). Additional Primary Metering requirements are defined on PSEG Long Island Construction Standard CS-8735 “Typical 15kV Primary Instrument Transformer Cubicle” and CS-8736 “Typical 5kV Primary Instrument Transformer Cubicle”.

~~9.2.~~8.2. Transformers

~~9.2.1.~~8.2.1. DER Interconnection Transformer Configuration

LIPA distribution feeders are designed to be operated in an effectively grounded state, as defined by IEEE C62.92.1, at all times. This includes any potential periods of islanding where the sole source(s) of energization of an isolated portion of the LIPA system is DER, even for short durations (cycles to seconds) prior to islanding detection or other protection operation. The achievement of proper grounding coordination and immediate detection of ground fault overvoltages on the LIPA feeder may depend on proper selection of the DER transformer winding configuration.

Transformers providing a ground source (zero-sequence admittance) will be loaded by the inherent imbalance of the distribution feeder voltage. During feeder open-phase conditions or ground faults the current flow in the transformer can be very large. DER owners are responsible for applying suitable transformer ratings and for providing protections for their ground-sourcing transformers. Required ground sources, however, may not be tripped or disconnected without first or simultaneously tripping the DER.

Because the source characteristics of inverter-based and rotating generator DER differ substantially, the DER transformer configuration requirements and guidelines are stated separately for each.

~~9.2.1.1.~~8.2.1.1. Inverter-Based DER

If the developer of an inverter-based DER facility provides the interconnection transformer, PSEG Long Island preference is to use a wye-grounded/wye-grounded transformer unless CESIR studies indicate that a ground source is required for the DER interconnection.

If a ground source is required, the following configurations may be applied:

a. Grounded-wye/delta interconnection transformer. (Note: the transformer winding configurations in this document are referenced as high voltage winding / low voltage winding or utility side / DER side.)

b. Interconnection transformer of any winding configuration with the provision of a separate primary-connected grounding transformer. The grounding transformer may be configured in grounded-wye/delta or with a zig-zag winding.

c. Grounded-wye/grounded-wye interconnection transformer with the provision of a separate secondary-connected grounding transformer. The grounding transformer may be configured in grounded-wye/delta or with a zig-zag winding.

Transformer impedances and neutral-to-ground reactor or resistor impedances shall be selected to provide primary-side zero-sequence shunt impedance within the range specified in the CESIR study.

~~9.2.1.2.~~8.2.1.2. Rotating Generator DER

All rotating generator (synchronous and induction) DER systems interconnecting with LIPA having aggregate capacity greater than 500 KVA must be grounded sources at the LIPA primary voltage connection. This may be achieved by one of the following configurations:

a. Grounded-wye/grounded wye interconnection transformer in combination with a generator having wye-connected armature windings that are either solidly grounded or grounded through a neutral impedance. Solidly grounded generators can be damaged due to high fault currents. The DER owner should be aware of this risk and design suitable protection.

b. Grounded-wye/delta interconnection transformer. (Note: the transformer winding configurations in this document are referenced as high voltage winding / low voltage winding or utility side / DER side.) This connection isolates the generator from zero sequence currents caused by a utility feeder ground fault.

c. Interconnection transformer of any winding configuration with the provision of a separate primary-connected grounding transformer. The grounding transformer may be configured in grounded-wye/delta or with a zig-zag winding. The generator may be ungrounded or grounded through high neutral impedance.

d. Grounded-wye/grounded wye interconnection transformer with the provision of a separate secondary-connected grounding transformer. The grounding transformer may be configured in grounded-wye/delta or with a zig-zag winding. The generator may be ungrounded or grounded through high neutral impedance.

Transformer impedances and neutral-to-ground reactor or resistor impedances shall be selected to provide an effectively grounded source to the LIPA primary system, as defined by IEEE C62.91.1. The ground source shall contribute sufficient current such that any ground fault on the LIPA system can be detected by the DER protection. The total ground current contributed to a ground fault at the LIPA substation by all ground-sourcing DER on a feeder shall not exceed 400 A.

In addition to the potential impact of DER ground sources on LIPA system relays, the fault current contribution by the DER must also not cause miscoordination or false operation of LIPA feeder relays. The aggregate contribution of all sources connected to a LIPA feeder shall not be more than 800A three phase fault at the LIPA substation bus.

~~9.2.2.~~8.2.2. Dedicated Transformer

PSEG Long Island reserves the right to require a DER facility to connect to the LIPA System through a dedicated LIPA transformer for secondary metering service. The transformer shall be provided by PSEG Long Island at the DER owner’s expense; purchased from PSEG Long Island. The transformer may be necessary to ensure conformance with PSEG Long Island safe work practices, to enhance service restoration operations or to prevent detrimental effects to other PSEG Long Island customers. The transformer that is part of the normal electrical service connection of a DER owner's facility may meet this requirement if there are no other customers supplied from it. A dedicated transformer is not required if the installation is designed and coordinated with PSEG Long Island to protect the LIPA System and its customers adequately from potential detrimental net effects caused by the operation of the DER.

If PSEG Long Island determines a need for a dedicated transformer, it shall notify the DER owner in writing of the requirements. The notice shall include a description of the specific aspects of the LIPA System that necessitate the addition, the conditions under which the dedicated transformer is expected to enhance safety or prevent detrimental effects, and the expected response of a normal, shared transformer installation to such conditions. The transformer will be a standard LIPA transformer as listed in DA 50005. If a non- LIPA configuration transformer is required for the interconnection, it shall be procured, installed and owned by the customer. The customer shall be responsible to maintain any spare units.

~~9.3.~~8.3. Switchgear

~~9.3.1.~~8.3.1. Interconnection Breaker

a. The DER system shall provide an interconnection breaker. This interconnection breaker may be located on either the primary or secondary side of the interconnection transformer. (Exception: if the interconnection transformer is rated 2000 kVA or greater, the interconnection breaker must be on the primary side.) The breaker shall be located within the DER facility on the customer's side of the demarcation. If the interconnection breaker is metalclad switchgear, it shall be a draw out type with provisions for installing a ground and test device supplied by the DER owner.

b. The interconnection breaker shall be capable of withstanding 220% of the interconnection breaker rated operating voltage.

c. For interconnection breakers rated at 480 Volts or less, operating voltage of the breaker shall be rated to withstand the greater of 220% of the operating voltage or two times the rated operating voltage of the interconnection breaker plus one thousand (1,000) volts.

d. Capacitive Trip Devices (CTD) are not acceptable.

~~9.3.2.~~8.3.2. Utility Disconnect/Isolation Switch

DER equipment shall be capable of being isolated from the LIPA system by means of an external, manual, visible, gang-operated, lockable, load break disconnecting switch. The disconnect switch shall be installed, owned, and maintained by the DER owner, and located electrically between the DER equipment and its interconnection point with the LIPA System.

The disconnect switch must be rated for the voltage and current requirements of the installation. The basic insulation level (BIL) of the disconnect switch shall be such that it will coordinate with that of LIPA's equipment. Disconnect devices shall meet applicable UL, ANSI, and IEEE standards, and shall be installed to meet all applicable local, state, and federal codes. (Applicable Local City Building Code may require additional certification.)

The disconnect switch shall be readily accessible to PSEG Long Island at all times and physically located such that it is within 10 feet of the PSEG Long Island metering point or within 10 feet of the LIPA service entrance, lockable with a 3/8 inch shank LIPA lock. If such location is not possible, the DER owner will propose, and PSEG Long Island will approve, an alternate location. The location and nature of the disconnect switch shall be indicated in the immediate proximity of the electric service entrance. The disconnect switch shall be clearly marked, "Generator Disconnect Switch," (the same wording shall also be used for electrical energy storage DER) with permanent 3/8 inch or larger letters or larger.

For installations above 600V or with a full load output of greater than 960A, a draw-out type circuit breaker with the provision for padlocking at the draw-out position can be considered a disconnect switch for the purposes of this requirement unless the use of such a circuit breaker is specifically prohibited by PSEG Long Island, based on site-specific technical requirements. If PSEG Long Island grants such use, the DER owner will be required, upon PSEG Long Island'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 PSEG Long Island followed immediately by PSEG Long Island 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, utilities may disconnect the electric service to the premise in order to isolate the DER system.

~~9.3.3.~~8.3.3. Circuit Breaker for Dedicated Feeder

For DER facilities interconnected to LIPA by means of a dedicated feeder, a breaker shall be installed in the LIPA substation. For DER capable of sustained voltage output while isolated from the LIPA system, inclusive of but not limited to synchronous generators, line-side potential transformers will be installed on each phase. These potential transformers are for voltage or synch-check relays configured to prevent closing the breaker into an unsynchronized DER. All costs incurred to purchase and place into service this circuit breaker and its associated buswork, disconnect switches, relays, instrument transformers, protective relays, and control wiring shall be at the DER owner's expense.

~~9.4.~~8.4. Ride-Through Capability

DER connecting to the LIPA system shall, as a minimum, have voltage and frequency disturbance ride-through capabilities specified by IEEE 1547. Voltage and frequency disturbance ride-through performance categories, defined in IEEE 1547, are assigned as follows:

a. Synchronous and induction generator DER shall meet or exceed the ride-through requirements specified for Performance Category I.

b. Photovoltaic or battery energy storage DER shall meet or exceed the ride-through requirements specified for Performance Category III.

c. All other inverter-based DER shall meet or exceed the ride-through requirements specified for Performance Category II.

~~9.5.~~8.5. Interconnection Control and Protection Requirements

Stated below are the standard protection and control requirements applicable to DER interconnections to the LIPA system, rated greater than 500 kVA, that are in addition to those specified by IEEE Std 1547.

In addition to the requirements specified here, PSEG Long Island may require additional protective functions on a case-by-case basis. If PSEG Long Island determines a need for additional functions, it shall notify the DER owner in writing of the requirements. The notice shall include a description of the specific aspects of LIPA's system that necessitate the addition, and an explicit justification for the necessity of the enhanced capability. Where applicable, PSEG Long Island may provide guidance on settings for those functions designated as being required, however the DER owner is still responsible to develop all settings for their equipment.

The DER owner's protection system shall detect any faults within the DER Owner's system and shall interrupt the current contribution from the LIPA system to any such fault.

No protective equipment specified by PSEG Long Island or required by IEEE 1547, shall be changed or modified at any time without the written consent of PSEG Long Island.

~~9.5.1.~~8.5.1. Grid-Following (Conventional) Inverter-Based DER Control and Protection

Requirements in this section apply to inverter-based DER interconnections. Inverter-based DER interconnections shall additionally comply with the general control and protection requirements specified in Section 8.5.4.

~~9.5.1.1.~~8.5.1.1. Protection Functions

All Inverter based DERs listed under UL1741 or UL-1741SA shall have integrated protective functions as required by IEEE 1547. In addition, DER facilities having an aggregate rating greater than 500 kVA shall provide additional/redundant protection functions by using utility grade protective relays.

The following are the minimum protective functions to be implemented by utility grade relays

a. Over/under voltage (59/27)

b. Over/under frequency (81O/U)

c. Phase & ground overcurrent (50P/51P/50N/51N)

d. Zero sequence overvoltage (3V0) protection (59G) (Refer to section 8.5.4.1)

The following are additional protective functions that may be required to be implemented by utility grade relays:

a. Sync Check (25), if not provided by the inverter. This requirement applies only to inverters capable of operating in a "grid forming" control mode while interconnected to the LIPA system.

b. Transformer differential relaying (87T). (See Section 8.5.4.3 for details).

c. Negative sequence overcurrent or overvoltage relays (depending on inverter control characteristics).

d. Directional power relays (32) (may be required to limit or prevent export of power to contractual agreements).

~~9.5.1.2.~~8.5.1.2. Re-Entry to Service (Interconnection Breaker Reclosing)

Reclosing of the interconnection breaker and re-entry of the DER to service ~~is allowed only after DER interconnection breaker is tripped by under/overvoltage and under/overfrequency protection functions, and,~~following any protective trips[8] shall be delayed until the LIPA system voltage and frequency have recovered and continuously remain within the following criteria for 300 s:

0.9 PU < Voltage < 1.05 PU

59.3 Hz < Frequency < 60.5 Hz

[8] "Trip" is not inclusive of momentary cessation required of Category III DER per IEEE 1547-2018.

PSEG Long Island, at its discretion, may require the DER Operating Instructions to prohibit automatic re-entry to service, with re-entry to service only by specific permission of the PSEG Long Island Distribution System Operator.

~~9.5.1.3.~~8.5.1.3. Direct Transfer Trip (DTT)

Direct Transfer Trip (DTT) is required for inverter based DER 2,000 KVA or greater. PSEG Long Island may also require DTT to be installed on installations smaller than 2,000 KVA for out of phase reclosing prevention (see Section 8.5.6) or if deemed necessary for the safe operation of the LIPA system.

~~9.5.2.~~8.5.2. Synchronous Generator and Grid-Forming Inverter DER Control and Protection

Requirements in this section apply to synchronous generator and grid-forming inverter DER interconnections. Synchronous generator and grid-forming inverter DER interconnections shall additionally comply with the general control and protection requirements specified in Section 8.5.4.

~~9.5.2.1.~~8.5.2.1. Protection Functions

Synchronous generator DER facilities shall have at least the following protective functions implemented by utility grade relays:

a. Synch check (25)

b. Over/under voltage (59/27)

~~c.~~ Over/under frequency (81O/U)

~~d.~~c. ~~Voltage restrained instantaneous/time overcurrent (50/51V)~~

~~e.~~d. Negative sequence overcurrent (46).

~~f.~~e. Phase and ground overcurrent (50P/51P/50N/51N)

~~g.~~f. Directional overcurrent (67)

~~h.~~g. Loss of excitation (40)

The following are additional protective functions that may be required to be implemented by utility grade relays:

a. Transformer differential relaying (87T). (See Section 8.5.4.3 for details).

b. Bus differential (87B)

c. Generator differential (87G)

d. Directional power relays (32) may be required to limit or prevent export power to contractual agreements.

e. Voltage restrained instantaneous/time overcurrent (50/51V)

~~d.~~f. Directional ground overcurrent (67G)

~~9.5.2.2.~~8.5.2.2. Re-Entry to Service (Interconnection Breaker Reclosing)

Synchronous generator DER may not reconnect to the LIPA system following a protection trip without the express clearance of the PSEG Long Island Distribution System Operator.

~~9.5.2.3.~~8.5.2.3. Direct Transfer Trip (DTT)

DTT is required for all synchronous generators greater than 500 KVA. DTT implementation requirements are specified in Section 8.5.6.

~~9.5.2.4.~~8.5.2.4. Synchronization

The DER owner shall be solely responsible for synchronizing its generator(s) or grid-forming inverters with the LIPA system and the design of the system. Synchronizing facilities shall be required for any DER using synchronous generators, grid-forming inverters, ~~-~~or where the Owner's system is capable of operation in isolation from the LIPA system (microgrid). Synchronizing facilities shall either consist of automatic synchronizing equipment or the means to perform manual synchronization. Automatic synchronizing equipment shall be optional.

Synch check relays are required across the interconnection breaker of a synchronous generator, grid-forming inverter, or microgrid. The existence of automatic synchronization equipment does not eliminate the requirement for a synch check relay. A total of four potential transformers shall be required, three on LIPA's side of the breaker and one on the DER side.

~~9.5.3.~~8.5.3. Induction Generator DER Control and Protection

Requirements in this section apply to induction generator DER interconnections. Induction generator DER interconnections shall additionally comply with the general control and protection requirements specified in Section 8.5.4.

~~9.5.3.1.~~8.5.3.1. Protection Functions

Induction generator DER facilities shall have at least the following protective functions implemented by utility grade relays:

a. Over/under voltage (59/27)

b. Over/under frequency (81O/U)

c. Phase and ground overcurrent (50P/51P/50N/51N)

d. Transformer differential relaying (87T). (See Section 8.5.4.3 for details).

~~9.5.3.2.~~8.5.3.2. Re-Entry to Service (Interconnection Breaker Reclosing)

Re-entry of the DER to service, following any protective trips, shall be delayed until the LIPA system voltage and frequency have recovered and continuously remain within the following criteria for 300 s:

0.9 PU < Voltage < 1.05 PU

59.3 Hz < Frequency < 60.5

If a project fails Screen S6, a longer return to service time is required.

PSEG-Long Island, at its discretion, may require the DER Operating Instructions to prohibit automatic re-entry to service, with re-entry to service only by specific permission of the PSEG Long Island Distribution System Operator.

~~9.5.3.3.~~8.5.3.3. Direct Transfer Trip (DTT)

Requirement for DTT for induction generator DER shall be determined by PSEG Long Island considering the characteristics of the DER facility's reactive compensation design and the relative system minimum loading relative to the aggregate generation capacity on the LIPA distribution feeder section.

~~9.5.4.~~8.5.4. General Protection Functional Requirements

~~9.5.4.1.~~8.5.4.1. Voltage Trip Settings

Under- and over-voltage trip functions, as specified in IEEE 1547, shall be set with the following thresholds and such as to achieve the following clearing times (The clearing time is the time between the start of the abnormal condition and the DER System ceasing to energize the LIPA system - interrupting device operating time plus relay time):

For DER assigned to ride-through performance Categories I and II by Section 8.4 of this document

Voltage Range (% of base voltage)	Clearing Time (seconds)	Clearing Time (cycles)
V ≤ 50	0.16	9.6
V ≤ 88	5.0	300
V ≥ 110	1.0	60
V ≥ 120	0.16	9.6

For DER assigned to ride-through performance Category III by Section 8.4 of this document

Voltage Range (% of base voltage)	Clearing Time (seconds)	Clearing Time (cycles)
V ≤ 50*	1.1	66
V ≤ 88	5.0	300
V ≥ 110*	2.0	120
V ≥ 120	0.16	9.6

*Category III DER shall cease current injection to the LIPA system ("momentary cessation" as defined by IEEE 1547-2018) within 0.083 seconds (5 cycles) for voltage less than 50% or voltage greater than 110%.

Over/under voltage relay functions, implemented by utility-grade relays, shall be provided by three (3) single phase voltage elements in the relay. The PT's shall be connected phase to ground to perform these functions.

For three-phase DER facilities where all transformers between the LIPA primary voltage level and the location of DER voltage sensing are not connected grounded-wye/grounded-wye, or if a ground source with an admittance greater than one per-unit on the base of the interconnection transformer rating is connected at the secondary voltage level, a site-specific protection study will be conducted by PSEG Long Island to determine the protection requirements.

The nominal primary line to line voltages on the LIPA distribution system are 13.2 kV and 4.16 kV, and nominal secondary voltages are 120/240 V (single phase), 208Y/120 and 480Y/277 V (three phase). Base voltages specified above are the nominal LIPA system voltages for the relevant Reference Point of Applicability as defined in IEEE 1547.

Zero Sequence Overvoltage (3V0) protection functions ~~(59G elements)~~ shall be set to clear Zero Sequence Overvoltage in no more than 1 second. The utility grade relay must have 59G protection elements designed by the relay manufacture that provide acceptable setting range limits for each element, and not be created using user-defined custom logic.

The pickup setting for this element may be any value but not exceeding 150% of nominal line to ground voltage. In addition to the max limits previously provided, it is advisable to set this element above the nominal line to ground voltage to prevent nuisance tripping for loss of a PT fuse.

~~9.5.4.2.~~8.5.4.2. Frequency Trip Settings

Under- and over-frequency trip functions, as specified in IEEE 1547, shall be set with the following thresholds and such as to achieve the following clearing times (The clearing time is the time between the start of the abnormal condition and the DER System ceasing to energize the LIPA system - interrupting device operating time plus relay time):

Frequency Range Hz	Clearing Time (seconds)	Clearing Time (cycles)
f ≤ 56.5*	0.16	9.6
f ≤ 58.~~0~~5*	~~180~~300	~~10800~~18000
f ≥ 61.~~0~~2	~~180~~300	~~10800~~18000
f ≥ 62.0	0.16	9.6

* The under frequency setting is a recommended setting based on NERC standard PRC-006-NPCC-1 Automatic Under frequency Load Shedding curve Figure 1.

~~9.5.4.3.~~8.5.4.3. DER Transformer Protection

All customer owned DER interconnection transformers shall have a fault interruption device (circuit breaker or fuse) on the primary side of the transformer and coordinated with LIPA feeder fuses. The largest LIPA owned fuses applied on the distribution system are a 100T (S&C TCC 170-6-2) for overhead fuses and a 200E (S&C TCC 153-4-2) for underground fuses. Depending upon the location of the interconnection on the distribution system, lower-current rated LIPA-owned fuses may be used and the developer must coordinate with those lower-rated fuses.

The DER relaying/fuses are required to clear all transformer low side faults such that 0.5 second coordination time interval (CTI) is maintained with the nearest upstream utility protective device. If 0.5 second CTI cannot be maintained then transformer differential relays shall be required to provide high side clearing for all transformer faults. The developer must provide the fuse characteristics and their proposed phase and ground overcurrent settings. The developer is required to perform a coordination study and this must be provided for review.

~~9.5.4.4.~~8.5.4.4. Protection of DER Equipment

Responsibility for protection of the DER system and its equipment against possible damage resulting from parallel operation with the LIPA distribution system lies solely with the DER owner.

LIPA transmission lines have automatic instantaneous reclosing and distribution feeders have either automatic instantaneous or time delay reclosing with a dead time as short as 12 cycles and as long as 30 seconds. It is the DER system owner's responsibility to protect its equipment from being reconnected out-of-synchronism with the LIPA system after automatic reclosing of a LIPA circuit breaker. Where direct transfer trip (DTT) is used or required, it is solely for protection of the LIPA system. Neither PSEG Long Island nor LIPA warrant that the DTT system will be absolutely effective in preventing out-of-synchronism reclosing of the DER.

Implementation of DER protection shall not interfere with or degrade any performance required in this document or in any applicable standard, including the latest version of IEEE 1547.

~~9.5.4.5.~~8.5.4.5. Coordination with Reclosing

"Instantaneous" reclosing is implemented as a standard practice on all LIPA overhead distribution feeders, except where modifications have been made to implement delayed reclosing. Out-of-phase reclosing of LIPA feeders significantly energized in an islanded state by DER can be damaging to LIPA system equipment, the equipment of other customers, and to the operating DER.

Where the DER interconnected to a feeder reaches sufficient aggregate capacity to sustain voltage greater than 20% of nominal during an islanding condition, and the feeder uses a reclosing delay less than 2.5 seconds, all additional DER capacity interconnected to that feeder shall be interconnected only on the condition that means are implemented to discontinue participation of these DER in sustenance of any island prior to LIPA circuit reclosing. DER anti-island technology, tested to meet a two-second island detection time per IEEE 1547.1, is not considered sufficient to comply with this requirement except where LIPA feeder reclosing delays have been extended to 2.5 seconds or longer.

The need for protection schemes to eliminate islands prior to circuit reclosing are related to the aggregate DER capacity on a LIPA distribution circuit section, circuit loading, and the types of DER interconnected. Protection system requirements shall be determined during the interconnection screening process or in a CESIR. For DER interconnections to feeders with less than 2.5 second reclosing delays, mitigating measures may include direct transfer trip (DTT), and hot-line blocking. For inverter based systems, increasing LIPA feeder reclosing delay to 2.5 seconds would eliminate the need for mitigating measures but the DER owner is responsible for all associated costs.

LIPA distribution systems are reconfigured to restore service following outages, facilitate maintenance, and to alleviate overloads. If the feeder section to which a DER is connected is reconfigured to be fed from an alternate source, the alternate source may not have delayed reclosing or hot-line blocking implemented. Therefore, it may be necessary to require DER to shut down for the duration of reconfigured operation.

For customer facilities which are fed from the load side of a LIPA owned Automatic Throw Over Switch (ATO), DERs are not permitted to interconnect on the load side of the ATO. The DER owner may request that PSEG Long Island investigate viable options to allow the DER to interconnect on the load side of this LIPA owned ATO. Some viable options may require – LIPA ATO to be reprogrammed to manual mode, customer DER to disable automatic reclosing (re-entry to service) of their DER system and coordination of switching and manual reclosing/re-entry with the PSEG Long Island Distribution System Operator. Note that PSEG Long Island will not provide any status signals from the LIPA owned ATO to the DER owner to be used in any protection or control scheme.

~~9.5.4.6.~~8.5.4.6. Hot Line Blocking Scheme

Implementation of hot-line blocking scheme on the LIPA feeder to which the DER is interconnected can be a sufficient means of providing reclosing coordination. To implement this scheme, the LIPA substation feeder breaker may require a set of three (3) line side potential transformers (PTs) to monitor the presence of voltage on the distribution feeder and to provide voltage to a synch check or voltage relay, which shall prevent closing the breaker into an unsynchronized DER generator. All costs incurred to purchase and place this system in service shall be at the DER owner’s expense. The physical constraints of many LIPA substations, however, do not allow addition of feeder-side PTs without major modification. Therefore, a hot line blocking scheme may not be feasible in such locations.

Hot line blocking may not be implemented on all possible alternate sources for a feeder section. Therefore, it may be necessary to require DER, normally connected to a feeder with hot-line blocking implemented, to disconnect whenever the distribution system is reconfigured such that the feeder section to which the DER is connected is fed from an alternate source.

~~9.5.5.~~8.5.5. Protection-Related Equipment

~~9.5.5.1.~~8.5.5.1. Relays

Utility grade relays, as defined in Section 2 are required in addition to the DER protection. For DER systems utilizing only one utility grade microprocessor relay, the interconnection breaker or the generator breaker(s) must be tripped via physical lockout relay (86) when the DER system's protective relaying system goes into an alarm condition and upon loss of relay power. Alternatively, DER may utilize two redundant utility grade protective relays to avoid tripping for relay alarm conditions.

The lockout relay (86) shall also be tripped by all protection functions except over/undervoltage and over/underfrequency protection functions. All other protective relay functions including relay failure must operate the lockout relay to trip and block breaker closing. Tripping from SCADA must also hit the Lock out relay. The lockout function must be provided by separate auxiliary relay (cannot be programmed in microprocessor relay).

The lockout function (86) described above must be electrically operated ~~reset~~and locally reset ~~-~~through manual intervention~~-~~, before the interconnect breaker can be reclosed. This is required regardless of whether automatic reclosing is used or not. Refer to Appendix D drawings for details.

The interconnection breaker may only be closed after the cause of trip has been investigated and cleared and closing is approved by the PSEG Long Island Distribution System Operator.

~~9.5.5.2.~~8.5.5.2. Current and Potential Transformers (CTs and PTs)

a. All relaying CTs shall be sized accordingly to avoid CT saturation for maximum fault current through the CT. Calculations for CT saturation shall be performed as per the latest revision of IEEE Std C37.110 to avoid saturation with a DC component in primary current wave (using system X/R ratio). All protective CT's must be C Class. If multi-ratio CTs are utilized, the CT saturation calculation must be performed based on CT ratio tap connected to the protective relays. Interconnection relaying and telemetering shall have dedicated CTs.

b. Three PTs shall be installed on the LIPA side of the interconnection breaker and shall be connected wye-grounded/wye-grounded.

c. One (1) additional potential transformer (PT) shall be required at the point of interconnection for synchronization with the LIPA system on the DER side of the interconnection breaker.

(Note: Revenue metering shall have separate dedicated CTs and PTs from interconnection relaying and telemetering. Revenue metering requirements are defined in section 8.1.3)

~~9.5.5.3.~~8.5.5.3. DER Station Battery/UPS

The DER station battery/UPS shall be sized for an eight hour duty cycle in accordance with latest revision of IEEE Standard 485. At the end of the duty cycle the battery/UPS shall be capable of tripping and closing all breakers. All utility grade relays, auxiliary/lockout relays, trip circuits, closing circuits, DTT equipment, Telco DTT equipment SCADA meter and SCADA equipment shall be supplied by an 8 hour duty cycle battery/UPS.

~~9.5.6.~~8.5.6. Direct Transfer Trip (DTT)

Requirements for DTT are dependent on DER rating, technology, and load on the LIPA feeder section relative to the aggregate DER capacity on the section. (See Screen P10 in Section 4. In addition, DTT may be required in other situations if it is determined that conditions exist that could jeopardize the reliability and security of the LIPA system. DTT is not required for DER connected to LIPA's system via a dedicated feeder. If other LIPA distribution load is ever connected to a dedicated feeder then DTT will be required at DER owner's expense.

Where DTT is required, implementation shall meet the following requirements:

a) Equipment capable of receiving direct transfer trip (DTT) from the LIPA substation and tripping the interconnection breaker shall be installed at the DER facility. A dedicated leased Digital T1 Circuit (Preferably on fiber transport) point to point communication circuit (B8ZS line coding with ESF) and RJ-48C jack with a full (1.544 Mbps, unchannelized) to be used for connecting RFL transfer trip equipment. If any part of T1 circuit is over metallic wires, that part of the circuit must be Type 4 with Class A SPO and no repeaters. This leased line shall be ordered and paid for by DER owner. This communication circuit is separate from the SCADA communication circuit specified in Section 8.5.7.

b) The DTT receiving equipment shall provide four outputs: two trip outputs, one major alarm output and one communication failure output. One of the trip outputs shall trip the interconnection breaker directly or through the lockout relay. DTT cannot trip the interconnection breaker through the utility grade protective relay.

c) When SCADA is required, the second output of the DTT equipment shall be wired to the RTU to provide DTT trip indication. The major alarm and communication failure outputs shall also be wired to the RTU.

d) The DTT equipment shall be mounted indoors or in an environmentally controlled outdoor enclosure.

e) The DER interconnection breaker shall not be closed, or remain closed, if the DTT system or associated lease line is out of service.

Specifications for transfer trip terminal equipment and associated transfer trip communication channel will be provided by PSEG Long Island. All costs associated with purchasing, engineering and installing DTT equipment at LIPA's substation shall be paid for by DER owner.

~~9.5.7.~~8.5.7. Supervisory Control and Data Acquisition (SCADA)

A DER with aggregate rating of 500 KVA or greater ~~or greater~~ shall require a SCADA (Supervisory Control and Data Acquisition) system Remote Terminal Unit (RTU). DER owner's RTU is required to use DNP 3.0 Serial Protocol. The supervisory equipment at the DER site shall be procured, installed, maintained and paid for by the DER owner. The supervisory equipment at the LIPA Operations Center will be procured, installed, maintained by PSEG Long Island and paid for by the DER owner. A dedicated leased TLS communication circuit AND/OR a wireless 4G backup is required for communication between the DER's RTU and LIPA's SCADA system (at LIPA's Operations Center). This leased line shall be the responsibility of the DER owner, including procurement, installation and maintenance. The DER owner shall also be responsible for all costs related to procurement, installation, maintenance and subsequent monthly charges. A DNP points list, otherwise known as "function tabs," will be provided by PSEG Long Island.

Projects 2MVA and greater – SCADA must communicate via Verizon Fiber based TLS line with 4G wireless as a backup.

Projects 500kVA to 1.99MVA: SCADA may communicate via only Verizon 4G wireless, unless it is determined that signal reliability is poor either prior to or after the project goes into service. If the signal reliability is poor, then the developer must add the Verizon TLS communication line even if the project is already in service.

4G/LTE minimum settings to have a wireless site accepted:

RSSI >= -80 Pass < -80 (-81 Fail)

SNR (sometimes noted as SINR) >= 5 Pass < 5 (4 Fail)

RSRP >= -105 Pass < -105 (-106 Fail)

RSRQ >= -12 Pass < -12 (-13 Fail)

The SCADA interconnection shall provide all monitoring information as specified in IEEE 1547. In addition, monitoring/control of the following key DER operating parameters via the SCADA shall be required:

1) Analog Monitoring

a) ~~Digital metering telemetry for per p~~Phase currents (IA, IB, IC) ~~-~~and Voltages (L-N).

b) Three phase Watts and Vars.

2) Digital Monitoring

~~c)~~ Breaker Status (52a)

~~d)~~c) ~~DER Breaker Trip (Lock out and this should automatically disable auto reclose)~~

~~e)~~d) Lockout Relay Trip Status (this should automatically disable auto-reclose)~~Reset~~

e) If DTT is installed the following points are required: DTT Communication alarm, DTT Equipment Status (equipment major alarm) and DTT received indication.

3) Digital Control

~~f)~~

f) Trip Lockout Relay

~~g)~~ Energy storage devices that will operate as independent dispatchable resources require additional SCADA monitoring and control points.

i. Alarm indicating unit Available/Unavailable.

ii. Start – digital control - Bring system online.

iii. Stop – digital control - Disconnect Inverters.

iv. Automatic control mode – digital control - System can manage charging and discharging automatically.

v. MW Setpoint.

vi. MVAR Setpoint.

DER Owner shall provide a list of additional information points available.

All analog values must be derived from CTs, located at the interconnection breaker, and line PTs. Additional digital and analog parameters may be required based on review of each individual DER.

PSEG Long Island may also require SCADA to be installed on installations smaller than 500 KVA if deemed necessary for the safe operation of the LIPA system. The DER shall not be allowed to operate in parallel with the LIPA system if the RTU or its associated lease line is out of service.

Modifications to the LIPA supervisory control and data acquisition (SCADA) system may be necessary to accommodate monitoring and control of the DER facility. All costs for additional hardware and software for LIPA's mainframe supervisory (SCADA) computer that are required for its interconnection shall be charged to the DER Owner.

~~9.6.~~8.6. Induction Generator Starting

DER systems utilizing induction generation may be connected and brought up to synchronous speed (as an induction motor) if it can be demonstrated that the initial voltage drop measured at the PCC is acceptable based on current inrush limits. The same requirements also apply to induction generation connected at or near synchronous speed because a voltage dip is present due to an inrush of magnetizing current. The DER owner shall submit the expected number of starts per specific time period and maximum starting kVA draw and power factor data to PSEG Long Island. The unit shall meet the requirements of LIPA DA 55104.

~~9.7.~~8.7. Reactive Power

DER shall have reactive power capability at the Reference Point of Applicability as defined in IEEE 1547. DER shall be operated at unity power factor unless otherwise specified by PSEG Long Island. Implementation of any of the reactive power control modes specified by IEEE 1547, and any related control parameters, may be required at any time by PSEG Long Island. Any required changes to control mode or parameters shall be implemented by the DER Owner, at their expense, within 30 days of notification by PSEG Long Island.

Flow of reactive power through the DER facility's metering point is subject to the appropriate PSEG Long Island tariff.

~~9.8.~~8.8. Engineering Studies

Engineering shall be performed by or on behalf of the DER Owner to determine the exact electrical configuration of the interconnection installation, and to identify any major equipment requirements such as circuit breakers and protective relaying.

~~9.8.1.~~8.8.1. Relay Coordination Study

The DER developer is required perform a protective relay coordination for three phase and line to ground faults on the LIPA system and faults within the DER facility. Note: The maximum available symmetrical short circuit current from LIPA on the 13kV distribution system is 16,000 amperes and is exclusive of any other DG Systems that may be connected to the same LIPA substation.

The relay coordination study will include coordination of relays applied at the DER facility as well as the impact of DER fault current contribution on LIPA system relays.

The study will determine the aggregate contribution of all DER sources connected to a LIPA feeder to a three phase fault at the LIPA substation bus. This aggregate contribution shall not exceed 800 A.

~~9.8.2.~~8.8.2. Grounding Study

For DER facilities that provide a ground source to the LIPA system, a grounding study must be performed with the following scope:

a. If a CESIR study has specified that the DER facility is required to provide primary-side zero-sequence shunt impedance within a certain range, the grounding study shall determine transformer impedances and neutral to ground reactor or resistor impedances to achieve this specification.

b. The study needs to demonstrate that effective grounding (coefficient of grounding less than 0.8), as per IEEE C62.92.1, is maintained on any LIPA system island which can potentially be energized by the DER. For rotating generators, this coefficient of grounding can also be achieved where impedance ratios X0/X1<3 and R0/X1<1 are satisfied. For inverter-based DER, guidance in calculating the coefficient of grounding is provided in IEEE C62.92.6.

c. The study needs to demonstrate that the aggregate contribution of all ground sources connected to a LIPA feeder is not more than 400A of ground current (3I0) for a line to ground fault at LIPA distribution substation bus with LIPA distribution feeder breaker closed.

A neutral reactor or resistor may be required to meet these requirements.

This grounding study shall be documented in a report, with a summary section at the beginning of the report documenting the DER's individual ground current contribution to the fault described above, the aggregate ground current contribution of all ground sources connected to the feeder, the Coefficient of Grounding (as defined in IEEE C62.92.1) and the parameters of any transformers, grounding transformers, and neutral reactors or resistors used to provide the ground source. The body of the report shall document impedances of all modeled power system elements such as generators, transformer and feeders in per unit with base MVA and voltage clearly stated. The report shall also document, the short circuit characteristics of inverters, including any current limits and negative sequence impedances.

For the purpose of performing the grounding study only, short circuit impedance data at the LIPA distribution bus, feeder impedance and short circuit impedance at the PCC, will be provided by PSEGLI Protection Engineering upon request. This grounding study must be approved by PSEG Long Island in order to confirm all requirements are met.

~~9.9.~~8.9. DER Drawing Requirements

DER Developer must submit a one line/relay functional diagram, three line ac diagram and dc schematics for review by PSEG Long Island. Example One Line/Relay Functional, DC Schematic and Three Line AC drawings are in appendix D which may be accessed at the PSEG Long Island website. Below are descriptions of these documents and the contents that must be included in each of these documents.

~~9.9.1.~~8.9.1. One Line/Relay Functional Diagram

a. Single line representation of the DER system and its interconnection with the LIPA system.

b. Switches, breakers, fuses, transformers, generation source, and LIPA feeder ID

c. Line of demarcation between LIPA equipment and developer's equipment.

d. Fuse ratings (Make, Model, and Time Curve Characteristic), CT ratios, CT accuracy class, PT ratios and connections of CTs and PTs

e. Current Transformer ANSI Voltage Rating ("C Rating") associated with Protective Relaying.

f. Transformer rating, impedance, winding configuration and connected voltages.

g. Generator rating, grounding and protection scheme.

h. Ratings for major equipment such as circuit breakers, switches, etc.

i. Name and model number of protective relays and meters.

j. Location identified where synch check function is performed, if synch check is required.

k. Relay protection scheme. Show tripping paths from protection devices to interrupting device.

l. Protective relay utilized inputs and outputs shall be clearly labeled.

m. ANSI designations shall be used to describe all protective relay functions.

n. If direct transfer trip (DTT) is required, then the signal path from receipt of DTT tripping via the lease line through to the interrupting device.

o. Protective functions and settings of the integrated control and protection package must be tabulated and depicted on the one line/relay functional diagram.

~~9.9.2.~~8.9.2. Three-Line AC Diagram

a. Three line representation of the representation of the DER system and its interconnection with the LIPA system.

b. Switches, breakers, fuses, transformers, generation source, and LIPA feeder ID

c. Lines of demarcation between LIPA equipment and developer's equipment.

d. Name and model number of protective relays and meters.

e. Fuse size, fuse ratings, CT ratios, CT polarity and PT ratios.

f. CT and PT connections to terminal points on protective relays and meters.

g. Transformer rating, winding connections and connected voltages.

h. If using test switches they must be clearly labeled with terminal and pole markings.

~~9.9.3.~~8.9.3. DC Schematics

a. Representation of tripping and control schemes of DER system interconnection breaker.

b. All inputs and outputs of protective relays and DTT equipment must be shown. States of all utilized contacts in de-energized position. Show terminal IDs of all inputs and outputs.

c. Device arrangement of lockout relays and switches.

d. DC power supplies and their voltage. Show power supply connections to Protective Relays, DTT Equipment and RTU.

e. DC fuse size.

f. Breaker trip and close circuits.

g. If using test switches they must be clearly labeled with terminal and pole markings.

~~9.10.~~8.10. Additional Documentation

~~9.10.1.~~8.10.1. Equipment Documentation

a. Transformer rating, positive sequence impedance, zero sequence impedance

b. Applicable to synchronous generators: Generator specification sheet with positive sequence sub-transient, transient and synchronous reactances, negative sequence and zero sequence impedances.

c. Applicable to inverters:

    i. Inverter manual

    ii. Inverter maximum fundamental-frequency short circuit current contribution.

d. DC power supply documentation showing adherence to IEEE-485

e. Interconnection breaker speed curve

f. Battery system spec sheet and maintenance procedure.

g. Fuse manufacturer, size, fuse ratings (including time curve characteristic (TCC) number).

h. Current transformer ANSI voltage rating (“C Rating”) for current transformers associated with protective relaying.

~~9.10.2.~~8.10.2. Protective Relay Documentation

a. Relay settings file

b. Relay settings summary sheet showing all active protective relay functions, pickups and time delays

c. Protection system functional test plan that provides details on tests that will be performed on DC circuitry, AC circuitry and relay logic

d. Protection system functional test and relay test reports. See Section 9 for full details.

~~10.~~9. DER Interconnection Commissioning and Testing

~~10.1.~~9.1. Single Phase Inverter DER Systems Rated 25 kW or Less

Single-phase inverters and inverter DER systems rated 25 kW aggregate nameplate rating and below shall be verified upon initial parallel operation and once every four years as follows: the DER owner shall interrupt PSEG Long Island's source and verify that the equipment automatically disconnects and does not reconnect for at least five minutes after PSEG Long Island's source is reconnected. The owner shall maintain a log of these operations for inspection by PSEG Long Island. Any system that depends upon a battery for trip power shall be checked and logged at least annually for proper voltage. Once every four (4) years the battery must be either replaced or a discharge test performed.

~~10.2.~~9.2. Other DER

DER not within the defined scope of Section 9.1 shall comply with all requirements of this section.

~~10.2.1.~~9.2.1. Verification Test Procedure

All interface equipment must include a verification test procedure as part of the documentation presented to PSEG Long Island. The verification testing may be site-specific and is conducted periodically to assure continued acceptable performance.

~~10.2.2.~~9.2.2. Pre-Interconnection Testing and Commissioning

At the completion of construction, functional tests, relay acceptance tests and calibration tests of all protective equipment shall be performed by a qualified testing company acceptable to PSEG Long Island, and PSEG Long Island reserves the right to witness such tests. If these tests are successful, and the protective relay settings have been correctly applied, PSEG Long Island shall permit the interconnection to be energized.

Upon initial parallel operation of a generating system, or any time interface hardware or software is changed, the verification test defined in 9.2.1 must be performed. A qualified individual must perform verification testing in accordance with the manufacturer's published test procedure. Qualified individuals include professional engineers, factory-trained and certified technicians, and licensed electricians with experience in testing protective equipment. PSEG Long Island reserves the right to witness verification testing or require written certification that the testing was successfully performed.

~~10.2.3.~~9.2.3. Recurring Tests

The DER owner shall procure the services of a qualified testing company, acceptable to PSEG Long Island, to perform maintenance, trip tests, and recalibration tests on its protective relaying devices once every six (6) years. A copy of the test results shall be sent to PSEG Long Island for review, comment, and acceptance, no later than five (5) working days after completion of tests.

Verification testing as defined in 9.2.1 shall be performed at least once every four years. In addition, all verification tests prescribed by the manufacturer shall be performed. If wires must be removed to perform certain tests, each wire and each terminal must be clearly and permanently marked. The DER owner shall maintain verification test reports for inspection by PSEG Long Island.

~~10.2.4.~~9.2.4. DER with Protective Relays at Interconnection Breaker

Any DER site that is required to install a protective relay(s) at their site for purpose of tripping the interconnection breaker or any other breaker at their site must submit protection system test procedures and protective relay acceptance test report as part of the documentation presented to PSEG Long Island for review. After protection system test procedure is reviewed by PSEG Long Island, it must be re-submitted with results of testing described in the procedure.

Developer will be required to provide their own site power and perform all the tests called for in their testing plan.

~~10.2.4.1.~~9.2.4.1. Protection System Testing Procedure and Functional Tests

Protection System Testing Procedure must include all of the following:

a. Relay serial # and part #.

b. Functional testing of all protective equipment. See description of functional tests below.

Protection System Functional Testing should include following (see Protection System Test Report in Appendix E):~~:~~

1) Trip tests to verify that all wired output contacts of all relays perform their intended function. Tests to verify all that output contacts intended to trip the breaker directly or through auxiliary relay perform this intended function. Tests to verify successful operation of all AC and DC circuits that perform tripping, re-closing, block closing and lockout.

2) All relay functions or logic programed in the relay intended to perform tripping, re-closing, block closing and breaker lockout must be verified by performing that function through output contact of the protective relay.

3) If protective system is designed to the trip the interconnection breaker when non-redundant relay goes into alarm then this function must be tested.

4) Test that breaker is locked out when tripped by appropriate protection functions.

~~10.2.4.2.~~9.2.4.2. Relay Acceptance and Calibration Tests

DER Owner must perform the following protective relay acceptance tests and provide results in the Protection System Test Report Appendix E:~~their report:~~

1) Test all protection functions programmed in the relay intended to trip, re-close, block or lockout a circuit breaker.

2) Validate all pick-up and operating time of each protection element. Each protection element must be tested per phase.

3) Test multiple points on curve of time overcurrent elements.

4) Tests for intentional time delays programmed in the relay.

5) Tests to validate any logic programmed in the relay that affects tripping, closing or reclosing of DER.

6) Relay visual and mechanical inspection.

7) Perform load checks. Load checks are typically performed after energization of the DER facility from LIPA.

~~11.~~10. DER System Operation

~~11.1.~~10.1. Ongoing Standard Compliance

The DER owner is responsible for maintaining compliance with the IEEE Standard 1547 version applicable at the time of initial DER facility commissioning and interconnection, or a later version of this standard at the DER owner's discretion, at all times while the DER system is interconnected with the LIPA system.

~~11.2.~~10.2. Operating Instructions

To provide for continuing operations in a safe, economical and efficient manner, PSEG Long Island shall prepare and deliver Operating Instructions to the DER owner prior to interconnecting the facility. The Operating Instructions shall include but not be limited to defining requirements for:

a. Maintaining proper voltage and frequency and for putting into effect voltage changes as required from time to time.

b. Phasing and synchronizing the facility and LIPA's system.

c. Taking feeders out of service for maintenance during a system emergency or system pre-emergency conditions and restoring such feeders to service.

d. Controlling the flow of real and reactive power.

e. Periodic maintenance of the interconnection circuit breaker and related facilities.

f. Procedure for communication between electrical operations personnel of the DG System and PSEG Long Island.

~~11.3.~~10.3. Generator Owner Point of Contact

The DER-owner shall provide a 24-hour telephone contact. This contact will be used by PSEG Long Island to arrange access for repairs, inspection or emergencies. PSEG Long Island will make such arrangements (except for emergencies) during normal business hours.

~~11.4.~~10.4. Modifications to DER System

Any modifications to the DER system that has an impact on the interface at the PCC, after it has been installed and a contract between LIPA and the generator-owner has already been executed, shall be subject to prior review and written authorization by PSEG Long Island.

No changes to voltage and frequency protection parameters shall be made without prior written authorization of PSEG Long Island. Voltage and frequency protection set point adjustments shall be accessible only to qualified service personnel.

Any changes to DER control and protection parameters, for which discretion has been assigned to the "Area EPS Operator" by IEEE Std 1547, shall be made by the DER Owner at the direction of PSEG Long Island. Changes shall be made as soon as possible and always within 30 days of notification by PSEG Long Island. Costs associated with making such parameter changes are the exclusive responsibility of the DER Owner.

~~11.5.~~10.5. Operation During LIPA System Outages

The DER facility shall not supply power to the LIPA system during any outages of the circuit that serve the PCC. The DER owner's generation may be operated during such outages only with an open tie to the LIPA system. Islanding of any portion of the LIPA system, energized by DER, will not be permitted. The generator-owner shall not energize a de-energized LIPA circuit for any reason.

~~11.6.~~10.6. DER Facility Disconnection

The DER facility may be disconnected from the LIPA system, except as prohibited by the latest version of IEEE 1547, without prior notice in order to self-generate or for any other reason.

The DER facility may be disconnected by PSEG Long Island or LIPA personnel by any or all of the following means:

a. Opening of the disconnect switch specified in Sections 7.5.1 or 8.3.2, as applicable.

b. Initiating direct transfer trip (DTT) where implemented,

c. Supervisory operation of the interconnection breaker specified in Section 8.3.1, where present,

d. Opening of a feeder breaker at the LIPA substation in the case of a DER facility connected to a dedicated feeder.

If a DER facility is locked out, except as resulting from an automatic protection action, PSEG Long Island will provide a name and telephone number so that the generator-owner can obtain information regarding the lock-out.

~~11.6.1.~~10.6.1. Disconnection at Any Time

A DER facility may be disconnected at any time, with or without prior notification of the DER owner or operator, for the following reasons:

a. To eliminate conditions that constitute a potential hazard to PSEG Long Island or LIPA personnel or the general public;

b. Pre-emergency or emergency conditions on the LIPA System;

c. A hazardous condition is revealed by a PSEG Long Island inspection;

d. Protective device tampering;

e. Parallel operation prior to PSEG Long Island approval to interconnect.

~~11.6.2.~~10.6.2. Disconnection with Prior Notification

A DER facility may be disconnected for the following reasons after notice is the responsible party has been delivered and a reasonable time to correct (consistent with the conditions) has elapsed:

a. A DER owner has failed to make available records of verification tests and maintenance of its protective devices;

b. A DER system adversely impacts the operation of LIPA equipment or equipment belonging to other customers;

c. A DER system is found to adversely affect the quality of service to adjoining customers.

Appendix A - Determination of DER Penetration Levels

A-1 Penetration Ratio

For the purposes of the preliminary screening process specified in this document, DER penetration is defined as the aggregate DER capacity installed on the particular feeder section or distribution system divided by the minimum concurrent load level for the same feeder section or distribution system. The aggregate DER capacity is inclusive of small DER (50 kW or less) as well as large DER (greater than 50 kW) and includes DER that has previously been interconnected or approved for interconnection and DER. For DER facilities having a certified Power Control System, the contribution of the facility to the total DER capacity shall be the power export limit specified in the Interconnection Agreement and maintained by the Power Control System.

As a simplification, solar PV DER is assumed to be capable of operating at rated capacity between the hours of ~~10~~ 9 am and ~~4~~ 5 pm local time. Because minimum loading levels on most LIPA feeders occur during hours of darkness, it is inconsistent to compare aggregate DER capacity that includes PV with absolute minimum load. Therefore, the penetration ratio PR shall be defined as follows:

$$\cancel{PR = \max\left[\frac{\sum P_{DER}}{MDL}, \frac{\sum P_{non-PV}}{ML}\right]}$$

$$PR = \max\left[\frac{\sum P_{DER}}{MDL}, \frac{\sum P_{non-PV}}{MNL}\right]$$

Where:

ΣP_{DER} = Aggregate summation of all DER capacity (inclusive of PV and non-PV) connected and reserved for connection to the respective feeder~~, feeder section,~~ or substation bus, as appropriate to the application of the penetration ratio.

ΣP_{non-PV} = Aggregate summation of all non-PVDER capacity connected and reserved for connection to the respective feeder~~, feeder section,~~ or substation bus.

MDL = Minimum daytime loading (~~10~~ 9 am to ~~4~~ 5 pm prevailing local time) for the respective feeder~~, feeder section,~~ or substation bus. (Actual load, not observed load net of existing DER generation.)

MNL = Minimum nighttime loading (5 pm to 9 am) ~~for any time of day~~ for the respective feeder~~, feeder section,~~ or substation bus. (Actual load, not observed load net of existing DER generation.)

Where minimum nighttime load data are not available, the ~~overall~~ minimum nighttime load may be assumed to be 30% of peak load, and minimum daytime load may be assumed to be 50% of peak load, except where special feeder circumstances can be identified (e.g., resort areas).

A-2 ASU and ACR Impacts on Penetration Ratio

For preliminary screening, penetration ratio is calculated on a total feeder basis. For supplemental screening, more accurate calculation of penetration shall be performed considering feeder configurations that may occur due to downstream automatic sectionalizer units (ASU) being open or upstream automatic circuit recloser (ACR) interruption of the circuit. Penetration ratios used for supplemental screens shall be the greater of the values based on the following conditions:

1. Entire feeder intact.
2. ASUs or ACR s on the main feeder downstream of the proposed DER connection (or where the lateral to which the proposed DER is to be connected meets the main feeder) assumed to be open. (There will be separate calculations for each downstream ASU or ACR.)
3. Upstream ACR (if any) open, with and without downstream sectionalizers or reclosers open.

Where minimum or maximum feeder section load data are not available, these ~~parameters~~ load data may be estimated pro-rata based on the feeder minimum or maximum load. The portion of total feeder load apportioned to the section may be based on the ratio of the section length divided by the total feeder length.

A-3 Correction of Recorded Feeder Load Data for Existing DER

Where existing DER decrease the net load in data that are extracted for the purpose of determining minimum load, the minimum load ML and minimum daytime load MDL used for penetration ratio calculations shall be determined as follows:

$$\cancel{ML = \min\left[\left(ML_{obs} + k_a \cdot P_{exn}\right), \left(m_a \cdot P_{pk}\right)\right]}$$

$$MNL = \min\left[\left(MNL_{obs} + k_n \cdot P_{exn}\right), \left(m_n \cdot P_{pk}\right)\right]$$

$$MDL = \min\left[\left(MDL_{obs} + k_d \cdot P_{exs}\right), \left(m_d \cdot P_{pk}\right)\right]$$

Where:

MNL_{obs} = Minimum nighttime net loading ~~for any time of day~~ (5 pm to 9 am) as observed in the recorded load data for the respective feeder, feeder section, or substation bus. This value is negative if there is reverse flow; i.e., DER generation exceeds load.

MDL_{obs} = Minimum daytime net loading as observed in the recorded load data for the respective feeder~~, feeder section,~~ or substation bus. This value is negative if there is reverse flow; i.e., DER generation exceeds load.

P_{exn} = Total non-PV DER capacity on the respective feeder~~, feeder section,~~ or substation bus. For DER facilities using a certified Power Control System, the power limit maintained by this Power Control System shall be used for this facility's contribution to the total DER capacity.

P_{ex} = Total DER capacity on the respective feeder, ~~feeder section,~~ or substation bus. For DER facilities using a certified Power Control System, the power limit maintained by this Power Control System shall be used for this facility's contribution to the total DER capacity.

P_{pk} = Peak load demand of the respective feeder~~, feeder section,~~ or substation bus.

$\cancel{k_a}k_n$ = Factor indicating the portion of installed non-PV DER capacity contributing to the ~~absolute~~ minimum nighttime load. This factor may be assumed to be 0.8.

k_d = Factor indicating the portion of installed capacity contributing to the minimum daytime load. This factor may be assumed to be 0.8.

$\cancel{m_a}m_n$ = Factor indicating the ratio of minimum nighttime load divided by peak load. This factor may be assumed to be 0.3.

m_d = Factor indicating the ratio of minimum daytime load divided by peak load. This factor may be assumed to be 0.5.

A-4 Equivalent Penetration Ratio

For certain screens defined in this document, the "stiffer" source provided by rotating generators (synchronous and induction) require the definition of an "Equivalent Penetration Ratio" (EPR). The calculation of EPR is similar to PR, except that the apparent power rating of rotating generators is increased by a weighting factor of six. The DER capacity used to calculate EPR shall be based on the gross DER capacity regardless of any export limits maintained by Power Control Systems.[9]

Equivalent penetration ratio (EPR) is defined by the following:

[9] UL 1741 tests for PCS require only a 30 second response time. While sufficient for steady-state purposes, this response is not sufficiently fast for the impacts for which EPR is used to screen.

$$EPR = \max\left[\frac{\sum P_{I-DER} + 6\cdot\sum S_{Rot}}{MDL}, \frac{\sum P_{I-non-PV} + 6\cdot\sum S_{Rot}}{MNL}\right]$$

Where:

$\Sigma P_{I\text{-}DER}$ = Aggregate summation of all inverter DER active power (kW) capacity (inclusive of PV and non-PV) connected and reserved for connection to the respective feeder, feeder section, or substation bus, as appropriate to the application of the penetration ratio.

$\Sigma P_{I\text{-}non\text{-}PV}$ = Aggregate summation of all non-PV inverter DER active power (kW) capacity (e.g., battery energy storage, fuel cell, etc.) connected and reserved for connection to the respective feeder, feeder section, or substation bus.

ΣS_{Rot} = Aggregate summation of the all rotating generator DER apparent power (kVA) capacity (induction and synchronous) connected and reserved for connection to the respective feeder, feeder section, or substation bus, as appropriate to the application of the penetration ratio.

Appendix B – Supplemental Screening Calculations

B-1 Steady-State Overvoltage Screen (S-1)

The steady-state overvoltage screen involves a series of tests. The tests that are applicable depend on the type of DER facility to be screened (PV or non-PV) and the rating of the facility (>300 kW defined as "large", or ≤ 300 kW defined as "small"). The tests and the DER to which the tests apply are shown in table B-1.1 below. If all the applicable criteria are met (inequalities are satisfied), then the DER passes this screen. Note that there are two tests (Tests 1.2a and 1.2b) applicable to large non-PV DER. Variables used in the table are defined in Table B-1.2.

The equivalent distance (d_{eq}) of existing large DER facilities on a feeder is defined by the following:

$$d_{eq} = \frac{\sum_n (P_n \cdot d_n)}{\sum_n P_n}$$

where P_n is the power rating of each existing large DER facility and d_n is the distance along the main feeder from the substation to the point of the respective large existing

DER's connection. Where a DER facility's power export is limited by a certified PCS, this facility's contribution to the aggregate power shall be the value specified in its Interconnection Agreement as regulated by the PCS.

The effective power P_{eff} of DER operating continuously at a pre-set non-unity power factor is modified by the following:

$$P_{effective} = P_{rated} \cdot \left(1 + 2.3 \cdot \frac{\sqrt{1 - pf^2}}{pf} \right)$$

where P_{rated} is the power rating of the DER, and *pf* is the operating power factor. By convention, the power factor pf used in this relationship shall have a negative value for a leading (VAR absorbing) power factor, and positive for a lagging (VAR supplying) power factor. (For example, if the power factor is 0.97 leading, the effective rating is 42.3% of the actual rating.)

Table B-1.1 Steady-State Overvoltage Tests

Test ID	Applicability	Test Description
1.1	Large PV DER	$\cancel{P_{new\_PV} + P_{ex} < MNDL \cdot \left[\left(1.75 - 0.9 \cdot \frac{d_{new}}{d_{tot}}\right) \cdot \frac{P_{new\_PV}}{P_{new\_PV} + P_{ex}} + \left(1.75 - 0.9 \cdot \frac{d_{eq}}{d_{tot}}\right) \cdot \frac{P_{ex}}{P_{new\_PV} + P_{ex}}\right]}$ $P_{new\_PV} + P_{ex} < MNetDL \cdot \left[\left(1.75 - 0.9 \cdot \frac{d_{new}}{d_{tot}}\right) \cdot \frac{P_{new\_PV}}{P_{new\_PV} + P_{ex}} + \left(1.75 - 0.9 \cdot \frac{d_{eq}}{d_{tot}}\right) \cdot \frac{P_{ex}}{P_{new\_PV} + P_{ex}}\right]$
1.2a	Large non-PV DER	$\cancel{P_{new\_non-PV} + P_{ex\_non-PV} < \frac{MNL}{P_{new\_non-PV} + P_{ex\_non-PV}} \cdot \left[\left(1.75 - 0.9 \cdot \frac{d_{new}}{d_{tot}}\right) \cdot P_{new\_non-PV} + \left(1.75 - 0.9 \cdot \frac{d_{eq\_non-PV}}{d_{tot}}\right) \cdot P_{ex\_non-PV}\right]}$ $P_{new\_non-PV} + P_{ex\_non-PV} < \frac{MNetL}{P_{new\_non-PV} + P_{ex\_non-PV}} \cdot \left[\left(1.75 - 0.9 \cdot \frac{d_{new}}{d_{tot}}\right) \cdot P_{new\_non-PV} + \left(1.75 - 0.9 \cdot \frac{d_{eq\_non-PV}}{d_{tot}}\right) \cdot P_{ex\_non-PV}\right]$
1.2b	Large non-PV DER	$\cancel{P_{new\_non-PV} + P_{ex} < \frac{MNDL}{P_{new\_non-PV} + P_{ex}} \cdot \left[\left(1.75 - 0.9 \cdot \frac{d_{new}}{d_{tot}}\right) \cdot P_{new\_non-PV} + \left(1.75 - 0.9 \cdot \frac{d_{eq}}{d_{tot}}\right) \cdot P_{ex}\right]}$ $P_{new\_non-PV} + P_{ex} < \frac{MNetDL}{P_{new\_non-PV} + P_{ex}} \cdot \left[\left(1.75 - 0.9 \cdot \frac{d_{new}}{d_{tot}}\right) \cdot P_{new\_non-PV} + \left(1.75 - 0.9 \cdot \frac{d_{eq}}{d_{tot}}\right) \cdot P_{ex}\right]$

Table B-1.2 Steady-State Overvoltage Test Variable Definitions

Variable	Definition
d_{eq}	Equivalent distance of existing large DER facilities on the feeder. See below for the calculation of this equivalent distance. (× 1000’)
d_{new}	Distance along the main feeder from the substation to the point of interconnection of the large DER being screened. (× 1000’)
d_{tot}	Total length of the main feeder. (× 1000’)

$MNetDL$	Minimum **net** daytime loading. Actual minimum demand of the feeder customer load between the hours of 10:00 and 16:00 minus the sum of all small (≤ 300 kW per interconnection) DER power ratings.
$MNetL$	Minimum **net** nighttime loading ~~at any time of day~~. Actual minimum demand of the feeder customer load minus the sum of all small (≤ 300 kW per interconnection) DER power ratings.
PR_{feeder}	Penetration ratio for the feeder, as defined in Appendix A
P_{new_PV}	Effective power rating ($P_{effective}$) of the PV DER being screened. See ~~below~~ above for definition of effective power rating.
$P_{new\_non\text{-}PV}$	Effective power rating ($P_{effective}$) of the non-PV DER being screened. See ~~below~~ above for definition of effective power rating.
P_{ex}	Aggregate effective power rating of the existing large DER (PV and non-PV) previously approved for interconnection
$P_{ex\_non\text{-}PV}$	Aggregate effective power rating of the existing large PV DER previously approved for interconnection

B-2 Steady-State Undervoltage Screen (S-2)

The steady-state undervoltage screen is a test to identify if the interaction of DER output with substation transformer tap changer line-drop compensation results in low voltage on the feeder having the least DER penetration. The allowable voltage decrease is 0.5 volts on a 120 V base. This screen is applicable to all DER, and is specified as:

$$\frac{P_{DER\_tot} \cdot V_R}{\sqrt{3} \cdot V_{nom} \cdot CT} \cdot \left(1 - \frac{P_{DER\_\min} / P_{Ld\_\min}}{P_{DER\_tot} / P_{Ld\_tot}} \right) \leq 1.0$$

Variables used in this specification are defined in Table B-2.1. If the inequality is satisfied then the DER passes this screen.

For this screen, the power capacity contribution of any DER having Power Control Systems shall be the power export limit established in that DER facility's Interconnection Agreement.

Table B-2.1 Steady-State Undervoltage Test Variable Definitions

Variable	Definition
CT	Ratio of the current transformer (CT:5) used to provide input to the substation transformer tapchanger control for line-drop compensation.
P_{DER_min}	Total DER capacity on the feeder with the least DER penetration relative to peak load that is supplied from the same substation bus as the feeder serving the DER being screened. (kW)
P_{DER_tot}	Total DER capacity on the substation bus. (kW)
P_{Ld_min}	Peak load on the feeder with the least DER penetration relative to peak load that is supplied from the same substation bus as the feeder serving the DER being screened. (kW)

P_{Ld_tot}	Peak load on the substation bus to which the feeder serving the DER being screened. (kW)
V_{nom}	Nominal primary line-to-line voltage of the distribution system (kV)
V_R	Resistive setting on substation transformer tapchanger control (Volts)

B-3 Voltage Variability Screen (S-3)

This screen identifies situations where the aggregate variability of DER power injection on a feeder may potentially result in excessive voltage variability. This screen exclusively applies to PV DER. DER that has reasonably constant power output under normal operation (e.g., cogeneration) may bypass this screen. Highly variable DER other than PV (e.g., wind power, and energy storage providing frequency regulation service) is not addressed by this screen and thus it must be relegated to a CESIR study (i.e., non-PV inherently variable DER that have not passed Preliminary Screening automatically fail Supplemental Screening and a CESIR must be performed).

For this screen, the power capacity contribution of any DER having Power Control Systems shall be the power export limit established in that DER facility's Interconnection Agreement.

For feeders having only small PV DER (≤ 300 kW), including the DER being screened, the screening criterion is:

$$\frac{P_{Small\_PV} \cdot d_{tot} \cdot R_{fdr}}{V_{nom}^{2} \cdot 5000} \le 0.02$$

Variables used in this specification and other specifications in this screen are defined in Table B-3.1.

For feeders that have no other PV interconnections (with the exception of retail DER with ratings less than 25 kW) than the large (>300 kW) or small (≤300 kW and > 25 kW) facility being screened, the screening criterion is:

$$\frac{0.8 \cdot P_{PV} \cdot d_{PV} \cdot R_{fdr}}{V_{nom}^{2} \cdot 1000} \le 0.02$$

For feeders that have existing PV interconnections (with the exception of retail DER with ratings less than 25 kW) the screening process involves three steps. The first step is to determine voltage variability ($\Delta V(n)$)associated with each large (>300 kW) PV facility (n).

$$\Delta V(n) = \frac{0.8 \cdot P(n) \cdot d(n) \cdot R_{fdr}}{V_{nom}^{2} \cdot 1000}$$

The second step is to determine which large PV facility has the largest voltage variability. The point on the main feeder to which this DER facility is connected is designated as the critical point.

For the third step, the screening is performed based on the voltage variability at the critical point, regardless whether this is the point of interconnection for the screened PV DER. The criterion applied to voltage variation at the critical point is specified as:

$$\frac{0.8 \cdot R_{fdr}}{V_{nom}^{2} \cdot 1000} \cdot \left(\begin{array}{l} 0.25 \cdot P_{Small\_PV} \cdot d_{tot} + \\ \sum\limits_{d(n)<d_{critical}} \left[P(n) \cdot d(n) \cdot k(n) \right] + d_{critical} \cdot \left(P_{critical} + \sum\limits_{d(n)>d_{critical}} \left[P(n) \cdot k(n) \right] \right) \end{array} \right) \leq 0.02$$

The correlation factor k is defined empirically to be:

$$\cancel{k(n) = \frac{0.9}{\sqrt[3]{s(n)}}}$$

$$k(n) = \max\left(\left(1 - {s(n)}/{2.7} \right), 0 \right)$$

where *s(n)* is the straight-line distance between the interconnection point of PV facility *n* and the critical point. Where *s* cannot be determined from GIS coordinates, it may be approximated by:

$$s(n) \approx \frac{\left| d(n) - d_{critical} \right|}{\sqrt{2}}$$

Table B-3.1 Voltage Variability Screen Variable Definitions

Variable	Definition
$d_{critical}$	Distance along feeder from the substation to the critical point. (× 1000’)
$d(n)$	Distance along feeder from the substation to the point of interconnection of PV facility *n*. (× 1000’)
d_{PV}	Distance along feeder from the substation to the point of interconnection of the single large PV facility undergoing screening. (× 1000’)
d_{tot}	Total length of the main feeder. (× 1000’)
$k(n)$	Correlation factor for the straight-line distance between the DER interconnection at point $d(n)$ and the critical point $d_{critical}$.
n	Index number of the DER facility. I.e., if there are four facilities on the feeder, they would be assigned indixes 1 through 4.
$P(n)$	Aggregate effective rating of DER facility *n*. (kW)
P_{PV}	Aggregate effective power rating of the DER facility being screened. (kW)
P_{Small_PV}	Sum of the effective power ratings of all small DER (individual facility ratings of ≤300 kW) connected to the feeder. (kW)

R_{fdr}	Resistance of the main feeder conductor. (Ω/1000’)
$s(n)$	Straight-line distance between the location of the DER under review and the location of DER facility n. (× 1000’)
V_{nom}	Nominal primary line-to-line voltage of the distribution system (kV)

B-4 LTC Duty Screen (S-4)

This screen identifies situations where DER power injection variability, interacting with the substation transformer's line-drop compensation, may result in excessive on-load tapchanger duty. This screen exclusively applies to inherently variable DER such as PV and wind, and to DER that is intentionally operated such as to have large and frequent changes in output power (e.g., battery energy storage providing frequency regulation service to NYISO). DER that has reasonably constant power output under normal operation may bypass this screen. This screen is defined as:

$$\frac{k_{vrb} \cdot P_{vrb\_tot} \cdot V_R}{\sqrt{3} \cdot V_{nom} \cdot CT} \leq V_{db}$$

Variables used in the specification above is defined in Table B-4.1. If the inequality is satisfied then the DER passes this screen.

For this screen, the power capacity contribution of any DER having Power Control Systems shall be the power export limit established in that DER facility's Interconnection Agreement.

Table B-4.1 LTC Duty Test Variable Definitions

Variable	Definition
CT	Ratio of the current transformer (CT:5) used to provide input to the substation transformer tapchanger control for line-drop compensation. (A)
k_{vrb}	Degree of frequent variability of DER. For PV use 0.8, for battery storage providing frequency regulation service (Reg Up and Reg Down) to the full extent of its rating in the charge and discharge directions, use 2.0.
P_{vrb_tot}	Total variable DER power rating connected to feeders supplied by the respective substation bus. (kW)
V_{nom}	Nominal primary line-to-line voltage of the distribution system (kV)
V_R	Resistive setting on substation transformer tapchanger control (Volts)
V_{db}	Deadband of substation transformer tapchanger control (Volts)

B-5 Tripping-Induced Undervoltage Screen (S-5)

This screen determines if simultaneous tripping of all DER connected to feeders supplied by a substation bus may result in customer voltages that are below the short-term limit (e.g., ANSI C84.1 Range B lower limit), and it applies to all DER (inclusive of small retail DER rated 25 kW or less).

This screen is defined as:

$$\frac{P_{DER\_tot} \cdot V_R}{\sqrt{3} \cdot V_{nom} \cdot CT} \leq 4.0$$

Where P_{DER_tot} is the sum the effective ratings of all DER connected to feeders supplied by the respective substation bus and all other variables are defined the same as in Table

B-4.1. For this screen, the power capacity contribution of any DER having Power Control Systems shall be the power export limit established in that DER facility's Interconnection Agreement.

If the inequality is satisfied then the DER passes this screen.

B-6 Return to Operation Overvoltage Screen (S-6)

This screen determines if simultaneous return to operation of all DER connected to feeders supplied by a substation bus may result in customer voltages that are above the short-term limit (e.g., ANSI C84.1 Range B upper limit), and it applies to all DER (inclusive of small retail DER rated 25 kW or less), except for DER designed to return to operation with a power ramp rate of 20% (of nameplate rating) per minute or slower.

This screen is defined as:

$$\frac{P_{DER\_NoRamp} \cdot V_R}{\sqrt{3} \cdot V_{nom} \cdot CT} \leq 1.0$$

Where P_{DER_NoRamp} is the sum the effective ratings of all DER connected to feeders supplied by the respective substation bus that do not recover with a ramped output increase less than 20% per minute. Power export limits regulated by PCS are not considered in this screen. Instead, gross DER inverter or generator nameplate capacity shall be used. All other variables in the specification above are defined the same as in Table B-4.1.

If the inequality is satisfied then the DER passes this screen.

B-7 Fault Current Contribution Screen (S-7)

This screen determines if the aggregate contribution of DER connected to a substation bus to fault currents exceed equipment ratings. This screen is applicable to both inverter-interfaced and rotating generator DER and is defined by the two criteria specified below:

$$\frac{2 \cdot S_{Inv\_total} + 6 \cdot S_{Rot\_total}}{\sqrt{3} \cdot V_{nom} \cdot 1000} + I_{no\_DER} \leq I_{momentary}$$

$$\frac{1.2 \cdot S_{Inv\_total} + 5 \cdot S_{Rot\_total}}{\sqrt{3} \cdot V_{nom} \cdot 1000} + I_{no\_DER} \leq I_{int\,errupting}$$

$$\frac{2 \cdot S_{Inv\_total} + 6 \cdot S_{Rot\_total}}{\sqrt{3} \cdot V_{nom} \cdot 1000} + I_{no\_DER} \leq I_{momentary} - I_{trans}$$

$$\frac{1.2 \cdot S_{Inv\_total} + 5 \cdot S_{Rot\_total}}{\sqrt{3} \cdot V_{nom} \cdot 1000} + I_{no\_DER} \leq I_{int\,errupting} - I_{trans}$$

If both tests are true (inequalities are satisfied), then the DER passes this screen. Variables used in these criteria are defined in Table B-7.1. Non-inverter-interfaced (i.e., synchronous and induction generator DER) automatically fail this screen and a CESIR is required. Power Control Systems (PCS) do not reliably limit short-circuit contribution. Therefore, the aggregate apparent power ratings used in this screen shall not consider the influence of PCS.

Table B-7.1 Fault Current Test Variable Definitions

Variable	Definition
$I_{interrupting}$	Rated interrupting current of any substation breakers. (kA)
$I_{momentary}$	Rated momentary (close and latch) current of any substation equipment. (kA).
$\cancel{I_{trans}}$	~~Short circuit contribution from the transmission system, through the substation bank, at the distribution bus, exclusive of DER contribution (kA)~~
I_{no_DER}	Substation fault current level with bus tie closed, without DER included. (kA)
S_{Inv_total}	Total apparent power rating of all inverter-interfaced DER connected to feeders supplied by the respective substation bus. (kVA)
S_{Rot_total}	Total apparent power rating of all rotating-generator DER connected to feeders supplied by the respective substation bus. (kVA)
V_{nom}	Nominal primary line-to-line voltage of the distribution system (kV)

B-8 Load Rejection Overvoltage Screen (S-8)

This screen determines if the aggregate action of DER on a feeder section can produce a severe load-rejection overvoltage. This screen is applicable to all inverter-interfaced DER. Rotating (synchronous and induction) generator DER automatically pass this screen. When both rotating and inverter-interfaced DER are on a feeder, the screen is applied ignoring the rotating generator capacity. For PV DER, only Test 8-1, specified in Table B-8.1, is applicable. For non-PV DER, both Test 8-1 and Test 8-2 are applicable. If the applicable tests are true (inequality is satisfied), then the DER passes this screen. Variables used in the specification of these tests are provided in Table B-8.2.

Power Control Systems (PCS) do not reliably limit contribution to load rejection overvoltage. Therefore, the aggregate apparent power ratings used in this screen shall not consider the influence of PCS.

The ratios of DER capacity to minimum load described in Table B-8.1 shall be the greatest ratios considering the feeder configurations described in Appendix A-2.

Table B-8.1 Load Rejection Overvoltage Tests

Test ID	Applicability	Test Description
8-1	~~PV~~ All inverter DER	$\frac{DER_{sub-ASU}}{MDL_{sub-ASU}} \cancel{\leq 1.4}$

		$\frac{P_{Inv}}{MDL} \le 1.4$
8-2	non-PV inverter DER	~~$\frac{NonPV_{sub-ASU}}{ML_{sub-ASU}} \le 1.4$~~ $\frac{P_{I-non-PV}}{MNL} \le 1.4$

Table B-8.2 Load Rejection Overvoltage Test Variable Definitions

Variable	Definition
~~DER_{sub}~~P~~$_{ASU}$~~$_{Inv}$	Total inverter-interfaced DER capacity (Large and Small, PV and non-PV) connected to the feeder ~~between the substation and the first ASU downstream of the screened DER PCC~~.(kW)
MDL~~$_{sub-ASU}$~~	Minimum daytime (~~10~~ 9 am – ~~4~~ 5 pm) load on feeder ~~between the substation and the first ASU downstream of the screened DER PCC~~. (kW)
MNL~~$_{sub-ASU}$~~	Minimum nighttime load (~~any time of day~~5 pm – 9 am) on feeder ~~between the substation and the first ASU downstream of the screened DER PCC~~. (kW)
~~Non~~P~~V~~~~$_{sub-ASU}$~~$_{non-PV}$	Total non-PV DER inverter-interfaced DER capacity connected to the feeder ~~between the substation and the first ASU downstream of the screened DER PCC~~. (kW)

B-9 Ground-Fault Overvoltage Screen (S-9)

This screen determines if the aggregated inverter DER on a feeder section has the potential to produce a severe ground-fault overvoltage. There are different tests that are applied depending if PV, or non-PV inverter-interfaced (e.g., fuel cell, battery storage) ~~), or rotating generator (synchronous or induction)~~ DER is to be screened. The tests, and the DER to which the tests apply, are shown in Table B-9.1 below. Note that there are two tests applicable to non-PV inverter-interfaced DER (Tests 9.1 and 9.2). Only test 9.1 is applicable to PV DER.~~Two different tests (Tests 9.3 and 9.4) are applicable to rotating generator DER.~~ If the applicable tests are true (inequality is satisfied), then the DER passes this screen. Variables used in the specification of these tests are ~~provided~~ defined in Table B-9.2.

The ratios of DER capacity to minimum load described in Table B-9.1 shall be the greatest ratios considering the feeder configurations described in Appendix A-2. Power Control Systems (PCS) do not reliably limit ground-fault overvoltages. Therefore, the aggregate apparent power ratings used in this screen shall not consider the influence of PCS.

A critical factor in this screen is the portion of load (k_Δ) that is connected phase-to-phase. Note that load may be effectively connected phase-to-phase even when the load is served by a wye-wye distribution transformer (e.g., three phase motors are typically connected in delta or floating wye, large facilities served at 480 V and higher may have delta-wye transformers within the facility to serve 120 V plug loads, some commercial lighting is connected phase-to-phase). A conservative assumption is that all commercial and industrial load is phase-to-phase connected and all residential load is phase-to-neutral connected.

Table B-9.1 Ground-Fault Overvoltage Tests

Test ID	Applicability	Test Description
9.1	~~PV DER and Non-PV Inverter-Interfaced~~All DER	$\cancel{\frac{DER_{sub-ASU}}{MDL_{sub-ASU}} \le 1.4 - 0.6 \cdot k_{\Delta}^{1.75}}$ $\frac{1.2 \cdot P_{Inv} + 6 \cdot S_{Rot}}{MDL} \le 1.4 - 0.6 \cdot k_{\Delta}^{1.75}$
9.2	Non-PV ~~Inverter-Interfaced~~ DER	$\cancel{\frac{NonPV_{sub-ASU}}{ML_{sub-ASU}} \le 1.4 - 0.6 \cdot k_{\Delta}^{1.75}}$ $\frac{1.2 \cdot P_{I-non-PV} + 6 \cdot S_{Rot}}{MNL} \le 1.4 - 0.6 \cdot k_{\Delta}^{1.75}$
~~9.3~~	~~Rotating DER~~	$\cancel{\frac{DER_{sub-ASU} + Rot_{sub-ASU}}{MDL_{sub-ASU}} \le 0.26 - 0.1 \cdot k_{\Delta}}$
~~9.4~~	~~Rotating DER~~	$\cancel{\frac{NonPV_{sub-ASU} + Rot_{sub-ASU}}{MDL_{sub-ASU}} \le 0.26 - 0.1 \cdot k_{\Delta}}$

Table B-9.2 Ground Fault Overvoltage Test Variable Definitions

Variable	Definition
$\cancel{DER_{sub}}P_{\cancel{-ASU}Inv}$	Total inverter-interfaced DER capacity (Large and Small, PV and non-PV) connected to the feeder ~~between the substation and the first ASU downstream of the screened DER PCC~~.(kW)
k_{Δ}	Ratio of load demand that is connected phase-to-phase divided by total load demand (ratio of commercial/industrial load demand to total load demand is a suitable approximation)
$MDL_{\cancel{sub-ASU}}$	Minimum daytime (~~10~~ 9 am – ~~4~~ 5 pm) load on feeder ~~between the substation and the first ASU downstream of the screened DER PCC~~. (kW)
$MNL_{\cancel{sub-ASU}}$	Minimum nighttime load (~~any time of day~~5 pm – 9 am) on the feeder ~~between the substation and the first ASU downstream of the screened DER PCC~~. (kW)
$\cancel{Non}P\cancel{V}_{\cancel{sub-ASU}I-non-PV}$	Total non-PV DER capacity connected to the feeder ~~between the substation and the first ASU downstream of the screened DER PCC~~. (kW)
$S\cancel{Rot}_{\cancel{sub-ASU}Rot}$	Total rotating generator (synchronous and induction) DER capacity connected to the feeder that do not provide effective grounding individually ~~between the substation and the first ASU downstream of the screened DER PCC~~.(~~kW~~kVA)

B-10 Circuit Protection Impact Screen (S-10)

This screen determines if the screened DER has significant potential to disrupt feeder protection coordination. There are separate tests based on positive and negative sequence current contribution, and zero sequence (ground) current contribution of the DER facility. The latter test is applicable only when the DER facility being screened provides a ground source (e.g., grounding transformer or grounded-wye/delta interconnection transformer), with the test also considering pre-existing feeder ground sources (exclusive of the substation ground source).

The test for aggregate positive and negative sequence current contribution is:

$$\frac{1.2 \cdot \Sigma S_{Inv} + 5 \cdot \Sigma S_{Rot}}{\sqrt{3} \cdot V_{nom} \cdot 1000} \leq 0.1 \cdot I_{SC}$$

For DER providing a ground source, the following additional test applies:

$$\frac{V_{nom} \cdot 1000}{\sqrt{3}} \cdot \sum_{n} \frac{1}{Z_0(n)} \leq 100 \text{ A}$$

The variables used in these tests are defined in Table B.~~9~~10-1.

Power Control Systems (PCS) do not reliably limit short-circuit contribution. Therefore, the aggregate apparent power ratings used in this screen shall not consider the influence of PCS.

Table B-10.1 Fault Current Test Variable Definitions

Variable	Definition
I_{SC}	Minimum short-circuit current level at screened DER point of connection if at primary voltage level, or at the primary side of the service transformer is the point of connection is at the secondary level. (kA)
ΣS_{Inv}	Sum of the apparent power ratings of all inverter-interfaced DER connected to the feeder. (kVA)
ΣS_{Rot}	Sum of the apparent power ratings of all rotating (synchronous and induction) DER connected to the feeder. (kVA)
V_{nom}	Nominal primary line-to-line voltage of the distribution system (kV)
$Z_0(n)$	Zero-sequence impedance of ground source *n* connected to the distribution feeder, as seen from the primary. (Ω)

B-11 Secondary Overvoltage Screen (S-12)

This screen determines if the DER can cause overvoltage for other customers served by the same distribution transformer and is defined as:

$$P_{effective} \leq 0.1 \cdot S_{xfmr} \cdot d \cdot (1 - PR_{feeder})$$

Variables used in this definition are provided in Table B-11.1. If a PCS is used to limit power export, the effective DER power rating used in this screen shall be the power export limit established in the DER facility's Interconnection Agreement.

Table B-11.2 Secondary Overvoltage Test Variable Definitions

Variable	Definition
d	Distance along feeder from substation to the point of interconnection of the DER being screened. (× 1000')
$P_{effective}$	Effective power rating ($P_{effective}$) of the PV DER being screened, considering the operating power factor of the DER. Definition and formula for this variable is provided in Appendix B-1. (kW)
PR_{feeder}	Penetration ratio for the feeder, as defined in Appendix A.
S_{xfmr}	Rating of the distribution transformer. (kVA)

Appendix C – Ground Sources

With exception[10], all DER interconnections with LIPA using rotating (synchronous or induction) generators must be grounded sources. During a phase to ground fault on the LIPA system, the distributed generator can be isolated with the phase to ground fault if the LIPA source opens before the DER system's protective equipment detects the fault condition and isolates from the LIPA system. If the generator is not grounded during the period it is isolated with the phase to ground fault, the neutral can shift resulting in overvoltage on the two remaining unfaulted phases. This overvoltage can reach 173% of normal and will damage LIPA phase to ground connected load or equipment isolated with the generator. To avoid the possibility of an overvoltage due to a neutral shift, LIPA requires that rotating generator DER systems provide a grounded source to the LIPA system. In some cases, LIPA may also require inverter-based and induction generator DER to provide a ground source.

The designer of the DER installation should be aware that the isolation transformer provides a path for zero sequence fault current for all phase to ground faults on the circuit. In order to limit the ground fault current from this transformer, LIPA may require that the system be designed to limit the zero sequence current (large zero sequence impedance) and still meet the grounding requirements.

There are several methods to ground a source. One accepted method is to use a wye grounded-delta step-up transformer (grounded-wye on LIPA side). An alternative method is to use a separate grounding transformer which may either use a zig-zag winding or grounded-wye delta winding configuration. If the generator is grounded (this is uncommon), a grounded-wye grounded-wye transformer may be acceptable.

An additional purpose of the wye-grounded (LIPA side)/delta (DG System side) isolation transformer is to filter out the third harmonics and multiples of the third harmonics and to provide a ground source that enables the DG System(s) protection to be able to detect ground faults on the LIPA system.

[10] If the aggregate ratings of all rotating generator ratings connected to, or reserved for connection to, a specific distribution system is less than 300 kVA, the requirement for providing a ground source may be excepted.

Appendix D – Example Diagrams.

Example One Line/Relay Functional, DC Schematic and Three Line AC drawings can be found on the PSEGLI website via the following link:

https://www.psegliny.com/aboutpseglongisland/ratesandtariffs/sgip/documents

Appendix E – Sample Distributed Energy Resource (DER) Interconnection Protection System Test Report

Information outlined in this sample test report must be submitted to PSEGLI as the final test report. The sample test report can be found on the PSEGLI website via the following link:

https://www.psegliny.com/aboutpseglongisland/ratesandtariffs/sgip/documents