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GOVERNMENT OF PUERTO RICO
PUERTO RICO PUBLIC SERVICE REGULATORY BOARD
PUERTO RICO ENERGY BUREAU

IN RE:
INTERCONNECTION REGULATIONS

CASE NO.: NEPR-MI-2019-0009

SUBJECT: Submittal of Additional Comments to Preliminary Draft of Proposed Generating Facility and Microgrid Interconnection Regulation

MOTION TO SUBMIT ADDITIONAL COMMENTS TO PRELIMINARY DRAFT OF PROPOSED GENERATING FACILITY AND MICROGRID INTERCONNECTION REGULATION

TO THE PUERTO RICO ENERGY BUREAU:

COME NOW, LUMA ENERGY, LLC as Management Co., and **LUMA ENERGY SERVCO, LLC** (collectively, LUMA), through the undersigned legal counsel and respectfully state and request the following:

On July 15, 2021, this Puerto Rico Energy Bureau of the Public Service Regulatory Board ("Energy Bureau") issued a Resolution and Order (the "July 15 Resolution") notifying that it had developed a draft for a new comprehensive interconnection regulation (titled *Generating Facility and Microgrid Interconnection Regulation*) ("Preliminary Draft") to govern the interconnection of distributed generators and microgrids. The Energy Bureau also indicated that before initiating a formal rulemaking procedure it was providing interested persons the opportunity to submit comments on the Preliminary Draft and invited LUMA and interested stakeholders to provide their comments and feedback to the Preliminary Draft on or before July 30, 2021. *See* July 15 Resolution at pp. 4-5. This Energy Bureau further indicated that "[t]he Energy Bureau's intention is to improve the Preliminary Draft before the formal rulemaking process commences". *See id*. at p. 4.

In the July 15 Resolution, this Energy Bureau also indicated, with respect to certain attachments referenced in the Preliminary draft, that: "As part of the Preliminary Draft, the Energy Bureau included several attachments, some of which may need to be modified. Some of the attachments to the Preliminary Draft were not included and will need to be developed. The Energy Bureau requests stakeholders to comment and suggest modifications to the included attachments as well as to propose content and format for those attachments not included." *See id*.

On July 30, 2021, LUMA submitted comments to the Preliminary Draft, in the form of a narrative document with general comments and a revised Preliminary Draft with LUMA's comments and incorporating some explicit edits. Given the limited time frame to submit these initial comments, the comments submitted by LUMA on July 30, 2021, were mostly of a conceptual nature and did not include all the proposed explicit changes to the regulation or the proposed Attachments that may be necessary to address the conceptual comments.

On August 3, 2021, the Energy Bureau provided the Independent Consumer Protection Office and any other interested parties an additional fourteen (14) days to submit their comments to the Preliminary Draft.

On September 10, 2021, the Energy Bureau issued a Resolution publishing the Spanish version of the Preliminary Draft and granted interested parties until September 30, 2021, to submit their comments to it.

On October 15, 2021, LUMA requested this Energy Bureau to provide LUMA until November 15, 2021 to submit additional and more detailed comments to the Preliminary Draft to address technical and practical issues that could arise in connection with the implementation of the proposed regulation. *See* LUMA's *Motion Requesting Additional Time to Submit Additional*

Comments to Preliminary Draft of Proposed Generating Facility and Microgrid Interconnection Regulation of that date ("LUMA's October 15th Motion").

In accordance with LUMA's October 15th Motion, LUMA hereby submits its more detailed comments incorporated in the draft of the Preliminary Draft, attached as *Exhibit 1*, in the form of balloon comments and specific text revisions to address these comments.

Although LUMA has included comprehensive comments to the provisions in the body of the Preliminary Draft, given the time constraints and complexity of the attachments to the Preliminary Draft, LUMA's comments on these attachments are pending further review. LUMA reserves the right to provide specific comments on these attachments, as well as to other parts of the proposed regulation, when and in the form and substance it is issued during the formal rulemaking proceeding by this honorable Energy Bureau. It must be noted, however, that LUMA is proposing some of the Attachments be either removed from the proposed regulation or be considered samples for further review, while establishing a mechanism whereby LUMA would prepare these documents and submit them separately to the Energy Bureau for the Energy Bureau's review and approval. LUMA respectfully submits that this mechanism would allow for revisions to these documents that may be needed due to changing circumstances without the need of engaging in a rulemaking proceeding every time such changes are needed, while maintaining the oversight of the Energy Bureau.

Similarly, in its attached comments, LUMA is also proposing that the detailed technical requirements for interconnection be removed from the regulation and made part of a separate technical document. To that effect, the proposed revisions also provide for the establishment of a mechanism under the regulation for LUMA to prepare the proposed technical requirements for the interconnections covered under the regulation (referred as "Technical Interconnection Requirements" or "TIR") and submit these separately to the Energy Bureau for the Energy Bureau's review and approval. LUMA respectfully submits that this mechanism will allow more flexibility in making revisions to this highly technical document to address changes in technologies, changes, revisions or updates to applicable technical codes and standards, and other changes in circumstances that would warrant revising or updating the document, without the need to trigger a rulemaking proceeding each time a change of such nature is required, while ensuring the Energy Bureau is able to review and determine whether it will approve or condition any such changes.

LUMA has prepared a preliminary draft of the TIR document that would be proposed for separate approval by this Energy Bureau, which is attached as Exhibit 2. The attached preliminary draft TIR document contains the proposed technical requirements for interconnection of Generating Facilities and Microgrids at the distribution level. Additional revisions are required to incorporate the technical requirements for interconnection at transmission/sub-transmission level. Given the complexities and detailed technical issues to be addressed in this document, LUMA respectfully submits that the preparation of a complete draft of this document will take additional time. Therefore, LUMA respectfully requests this Energy Bureau to accept this preliminary draft of the TIR as a demonstration of LUMA's progress in the preparation of a comprehensive TIR document and provide LUMA additional time to complete this document separately but contemporaneously with the review of the proposed regulation.

WHEREFORE, LUMA respectfully requests this honorable Energy Bureau to **take notice** of the above and **accept** LUMA's comments included herein to the Preliminary Draft of the *Generating Facility and Microgrid Interconnection Regulation* as well as the preliminary draft of the proposed Technical Interconnection Requirements and provide LUMA additional time to submit a more comprehensive draft of the TIR at a later date for separate review and approval by this honorable Energy Bureau outside the formal rulemaking proceeding.

RESPECTFULLY SUBMITTED.

In San Juan, Puerto Rico, this 15th day of November 2021.

We certify that we filed this motion using the electronic filing system of the Puerto Rico Energy Bureau.

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/s/ Laura T. Rozas
Laura T. Rozas
RUA Núm. 10,398

Exhibit 1

LUMA's Comments to Preliminary Draft of the Generating Facility and Microgrid Interconnection Regulation

GOVERNMENT OF PUERTO RICO

Public Service Regulatory Board
Puerto Rico Energy Bureau

Generating Facility and Microgrid Interconnection Regulation

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GENERAL PROVISIONS

Compliance with this Regulation shall relieve no Party affected by this Regulation from complying with other applicable legal and regulatory requirements enforced by any other Government Entity.

SECTION 1.01. Title

This Regulation shall be known as the *Generating Facility and Microgrid Interconnection Regulation* ("Regulation").

SECTION 1.02. Legal Basis

The Energy Bureau of the Public Service Regulatory Board ("Energy Bureau") adopted this Regulation pursuant to Act 82-2010, as amended, known as the *Public Policy on Energy Diversification by Means of Sustainable and Alternative Renewable Energy in Puerto Rico Act*; Act 17-2019, known as the *Puerto Rico Energy Public Policy Act*; Act 57-2014, as amended, known as the *Puerto Rico Energy Transformation and RELIEF Act*; and Act 38-2017, known as the *Uniform Administrative Procedures Act of the Government of Puerto Rico* ("LPAU" for its Spanish acronym).

SECTION 1.03. Purpose and Executive Summary

This Regulation provides the rules and procedures for the interconnection of Generating Facilities and Microgrids to the Electric Power System in Puerto Rico.

SECTION 1.04. Applicability

This Regulation supersedes the Regulation to Interconnect Generators to the Electric Distribution System of the Electric Power Authority and Participate in the Net Metering Programs, Regulation No. 8915, dated February 6, 2017, and the Regulation to Interconnect Generators to the Electric Transmission and Sub-transmission Systems of the Electric Power Authority and Participate in the Net Metering programs, Regulation No. 8916, dated February 6, 2017. This Regulation applies to any Generating Facility or Microgrid seeking to interconnect to the Electric Power System, except those that only operate independently of the Electric Power System (*i.e.*, not in Parallel Operation). Customers may participate in Net Metering Programs pursuant to Article 7 of this Regulation and Act 114-2007, known as the Puerto Rico Net Metering Act, as amended.

Commented [A1]: This document does not include many of the necessary technical details, policies and procedures pertaining to generating facilities and microgrid interconnection. LUMA is in the process of preparing a Technical Interconnection Requirements document that provides these details.

SECTION 1.05. Interpretation

This Regulation shall be interpreted so it promotes the highest public benefit and consumer protection, and in such a way that proceedings are carried out rapidly, justly, and economically~~.~~ and to ensure that the integration of renewable energy to the Electric Power System is made in a safe and reliable manner and without affecting the reliability and stability of the electric power system.

Commented [A2]: These are among the relevant public policy goals of Act 17.

SECTION 1.06. Provisions of Other Regulations

This Regulation may be supplemented by other regulations of the Energy Bureau consistent with this Regulation.

SECTION 1.07. Unforeseen Proceedings

When a specific proceeding has not been planned for in this Regulation, the Energy Bureau may attend to it in any way that is consistent with Act 114-2007, Act 57-2014, Act 17-2019, and any other applicable laws.

SECTION 1.08. Dates and Time Periods

In computing any time period established in this Regulation, or by Order of the Energy Bureau, the day of the act, event, or noncompliance that triggers the period shall not be counted, and the established period shall begin to elapse on the following calendar day. Whenever a due date falls on a Saturday, Sunday, or legal holiday, said due date shall be extended until the next Business Day.

SECTION 1.09. Definitions

A. These definitions are to be used for this Regulation and are not intended to modify the definitions used in any other Energy Bureau Regulation or Order.

B. For this Regulation, the following terms will have the meaning established below, unless the context of the content of any provision clearly indicates something else:

(1) "Aggregate Net Metering Program" – means the extension of the Basic Net Metering Program, created as fulfillment of the Puerto Rico Energy Bureau's Amended Order CEPR-MI-2014-0001[1]. This allows a participant to ~~accredit~~credit the excess energy produced by a Generating Facility using Renewable Energy Sources between service agreements under the same customer name, located at the same location as the Generating Facility or at different locations, as long as it meets the conditions set out in Article 7, Section 7.03 of this Regulation.

(2) "Basic Net Metering Program" – means the service provided to customers with Generating Facilities that use Renewable Energy Sources, interconnected with the EPS, as provided by Act 114-2007. This program allows for the accounting of the energy flow to and from the customer premises through the bidirectional meter. This system supplies part or all of the electrical demand consumed at the site where the system is located. At the end of the billing period, the EPS Operator

[1] See, Resolución y Orden, In Re: Autoridad de Energía Eléctrica, Oficina Estatal de Política Pública Energética, Case No. CEPR-MI-2014-0001, July 22, 2016.

shall bill net consumption by the customer or will credit on the next bill any excess of energy exported to the electrical grid.

(3) "Billing Period" – means the interval of time between one billing statement date and the next billing statement date. The billing period is the time for which energy use and credits for energy exports are calculated.

(4) "Business Day" – means Monday through Friday, excluding Federal and local holidays.

(5) "Cease to Energize" – means the cessation of active power delivery under steady-state and transient conditions and limitation of reactive power exchange. This does not necessarily imply, nor exclude disconnection, isolation, or a Trip. Limited reactive power exchange may continue as specified (*e.g.*, through filter banks).

(6) "Confidential Information"- means any confidential and/or proprietary information provided by one Party to the other Party clearly marked or otherwise designated "Confidential." For purposes of this Regulation all design, operating specifications, and Metering data provided by the Interconnection Customer shall be deemed confidential information regardless of whether it is clearly marked or otherwise designated as such. Confidential Information does not include information previously available in the public domain, required to be publicly submitted or divulged by Governmental Authorities (after notice to the other Party and after exhausting any opportunity to oppose such publication or release), or necessary to be divulged in an action to enforce this Regulation. Each Party receiving Confidential Information shall hold such information in confidence and shall not disclose it to any third party nor to the public without the prior written authorization from the Party providing that information, except to fulfill obligations under this Regulation, or to fulfill legal or regulatory requirements.

(7) "Credit for Energy Export" – means a credit in kilowatt hour (kWh) for the excess of exported energy during a billing period. This credit applies for the next billing period.

(8) "Cyber Portal" – means an internet site where Parties can electronically submit all documents required by this Regulation, monitor the Fast Track Process and Study Process, and approve the interconnection. This site also provides the ability to electronically sign agreements required in this Regulation.

(9) "Distribution System" – means the physical equipment used to distribute electric power at voltages below 38,000 volts, including but

not limited to poles, primary lines, secondary lines, service drops, transformers and Meters.

(10) "Distribution Upgrades" – means the additions, modifications, and upgrades to the Distribution System at or beyond the Point of Common Coupling to facilitate interconnection of the Generating Facility(ies) or the Microgrid and render the distribution service necessary to effectuate the connection to the Distribution System. For Microgrids with multiple Generating Facilities connected to the Distribution System, Distribution Upgrades may occur behind the Microgrid Point of Common Coupling. Distribution Upgrades do not include Interconnection Facilities.

(11) "Electric Power System" or "EPS" – means the Puerto Rico electric power Transmission and Distribution System, excluding equipment owned by Interconnection Customers.

(12) "Electric Power System Operator" or "EPS Operator" – means the entity that controls or operates the Electric Power System.

(13) "Energy Bureau" – means the Puerto Rico Energy Bureau, established by virtue of the Reorganization Plan of the Puerto Rico Public Service Regulatory Board, and Act No. 211-2018, known as the *Reorganization Plan Execution Act of the Public Service Regulatory Board,* formerly the Puerto Rico Energy Commission created under Act 57-2014, which is a specialized independent entity in charge of regulating, overseeing, and enforcing the public policy on energy of the Government of Puerto Rico.

(14) "Energy Storage" – means a device that captures energy produced at one time, stores that energy for a period of time, and delivers that energy as electricity for use at a future time.

(15) "Enter Service" – means to begin operation of the Generating Facility or Microgrid with an energized EPS.

(16) "Export Capacity" - means the Nameplate Rating of a Generating Facility or Microgrid in alternating current (AC), unless such capacity is limited by an acceptable means as identified in Section 1.47~~Section 5.12~~1.47.

(17) "Fast Track Process" – means the procedures in ~~Article 3~~Article 3 for evaluating an Interconnection Application that meets the eligibility requirements of Section 1.27~~Section 3.01~~1.27 and includes the initial review screens, customer options meeting, and optional supplemental review.

(18) "Force Majeure Event" – means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure Event does not include an act of negligence or intentional wrongdoing.

(19) "Generating Facility" – means the device(s) for the production and/or storage for later injection of electricity identified in the Interconnection Application. This shall include the Generating Facility and Microgrid's Interconnection Facilities, but not the EPS Operator's Interconnection Facilities.

(20) "Good Utility Practice" – means the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the time period, or the practices, methods and act which, in exercising reasonable judgment, given the facts known when the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

(21) "Governmental Authority" or "Government Entity" - means the government of Puerto Rico, any political subdivision thereof, and any agency, authority, instrumentality, regulatory body, board, bureau, court, or other entity exercising executive, legislative, judicial, taxing, regulatory or administrative powers or functions of or pertaining to government.

(22) "Host Load" - means the electrical power consumed at the interconnection site.

(23) "Inadvertent Export" - means the unscheduled export of power exceeding a contractually specified magnitude and for a limited duration.

(24) "Intentional Island" – means a planned electrical Island capable of being energized by one or more Generating Facilities. These (1) have Generating Facility(ies) and load, (2) have the ability to disconnect from and to operate in Parallel with the EPS, (3) include one or more customers, and (4) are intentionally planned.

(25) "Interconnection Agreement" – means the agreement provided in Attachment 8~~Attachment 8~~ to this Regulation.

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(26) "Interconnection Application" – means the Interconnection Customer's request to interconnect a new Generating Facility or Microgrid, or to increase the Nameplate Rating of, or make a Material Modification to the operating characteristics of, an existing Generating Facility or Microgrid that is interconnected with the Electric Power System.

(27) "Interconnection Customer" – means any entity or individual, including PREPA, the Electric Power System Operator, their affiliates and subsidiaries, that proposes to interconnect to the Electric Power System.

(28) "Interconnection Facilities" – means the EPS Operator's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities (collectively, "Interconnection Facilities") which include all facilities and equipment between the Generating Facility or Microgrid and the Electric Power System, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facilities and/or Microgrid to the Electric Power System. For Microgrids with multiple Generating Facilities, Interconnection Facilities may occur behind the Microgrid Point of Common Coupling. Interconnection Facilities are facilities used solely by the Interconnection Customer's Generating Facility and shall not include Distribution Upgrades or Network Upgrades.

(29) "Interconnection Ombudsperson" – means a person appointed by the Energy Bureau to facilitate resolution of disputes regarding the interconnection process and to track and monitor the interconnection process, amongst other duties, as defined by the Energy Bureau.

(30) "Interconnection Transformer" – means the transformer through which the Generating Facility interconnects with the EPS. This may also be the electrical transformer that supplies energy to the Host Load.

(31) "Island" – means a condition in which a portion of an EPS is energized solely by one or more Generating Facilities while that portion of the EPS is electrically separated from the rest of the EPS on all phases to which the Generating Facility is connected. When an Island exists, the Generating Facility energizing the Island may be said to be "Islanding" or "Islanded." Islands may be Intentional or Unintentional.

(32) "Limited Export" - means the exporting capability of a Generating Facility or Microgrid whose Export Capacity is limited below the Nameplate Rating by any configuration or operating mode described in Section 1.47~~Section 5.121.47~~.

(33) LUMA Energy Servco LLC - a limited liability company organized under the laws of the Commonwealth of Puerto Rico ("LUMA" or "Operator") under the terms of the Operation and Maintenance Agreement dated as of June 22, 2020, as amended from time to time in accordance with its terms (including any amendments as may be contemplated by the Supplemental Agreement (as defined in Exhibit F-1 to such agreement)).

~~(33)~~(34) "Material Modification" – means a modification to machine data or equipment configuration or to the interconnection site after receiving notification by the Electric Power System Operator of a complete Interconnection Application with a material impact on the cost, timing, or design of any Interconnection Facilities or Upgrades, or a material impact on the cost, timing or design of any Interconnection Application with a later queue priority date. A Material Modification shall include, but may not be limited to, a modification from the approved Interconnection Application that: (1) increases the Nameplate Rating, Export Capacity, Operating Profile, or output characteristics of the proposed interconnection; (2) changes or replaces generating equipment, such as generator(s), inverter(s), transformers, relaying, controls, etc., and substitutes equipment that is not a like-kind substitution in certification, size, ratings, impedances, efficiencies or capabilities of the equipment; (3) changes transformer connection(s) or grounding; and/or (4) changes to certified inverters with different specifications or different inverter control specifications or set-up.

A Material Modification shall not include a modification from the approved Interconnection Application that: (1) changes in ownership; (2) changes the address, so long as the proposed interconnection remains on the same parcel(s); (3) changes or replaces generating equipment such as generator(s), inverter(s), solar panel(s), Energy Storage device(s), transformers, relaying, controls, etc. and substitutes equipment that is a like-kind substitution in certification, size, ratings, impedances, efficiencies or capabilities of the equipment; and/or (4) changes the DC/AC ratio but does not increase the maximum AC output capability of the proposed interconnection.

~~(34)~~(35) "Meter" or "Metering" – means the equipment or instruments which function is to measure and register the bi-directional flow of electric energy (*i.e.*, energy delivered and received) by a Generating Facility or Microgrid interconnected to the EPS.

~~(35)~~(36) "Microgrid" – means a group of interconnected loads and Generating Facilities within clearly defined electrical boundaries that acts as a single controllable entity that can connect and disconnect from the Electric Power System to enable it to operate in either Parallel (grid-connected) or Islanded (off-the-grid) mode. This shall include the Interconnection Customer's Interconnection Facilities. In some cases, the EPS Operator's Interconnection Facilities may also be included in the Microgrid.

~~(36)~~(37) "Minor System Modifications" – means modifications to the Electric Power System or other minor system changes that the Electric Power System Operator estimates will entail less than ten (10) hours of work and five thousand dollars ($5,000) in materials. The Electric Power System Operator may also deem other more substantial work, including the upgrade of transformers, as Minor System Modifications at its discretion.

~~(37)~~(38) "Nameplate Rating" – means the sum of the maximum rated output of all generators, prime movers, Energy Storage systems, or other electric power production equipment under specific conditions designated by the manufacturer and usually indicated on a nameplate physically attached to the power production equipment. The Nameplate Rating may be distinct from the Export Capacity where a facility uses export controls pursuant to Section 1.47~~Section 5.12~~1.47 and Section 1.47.A~~Section 5.12~~1.47.A.

~~(38)~~(39) "Nationally Recognized Testing Laboratory" or "NRTL" – means an accredited laboratory that performs certification tests required by Institute of Electrical and Electronics Engineers and American National Standards Institute (ANSI) standards .

~~(39)~~(40) "Net Consumption" – means the resulting amount from subtracting the Interconnection Customer's consumed energy from the energy exported to the EPS and credits for energy export, if any. Applied when the energy the Customer consumes is greater than the energy exported and any applicable exported energy credits.

$$\text{Cnet} = \text{kWhcon} - \text{kWhexp} - \text{CRexp}$$

Where:

Cnet = net consumption

kWhcon = kWh kilowatt-hours consumed

kWhexp = kWh kilowatt-hours exported

CRexp = credit for energy export (from previous billing period)

~~(40)~~(41) "Net exports" – means the resulting amount when the sum of the energy exported by the Interconnection Customer's to the EPS and credits for energy export, if any, are subtracted from the energy consumed by the Customer. Applied when the energy consumed by the Customer is less than the sum of the energy exported and any applicable credits for energy exports.

Enet = kWhexp + CRexp - kWhcon

Where:

Enet = net export

kWhcon = kWh kilowatt-hours consumed

kWhexp = kWh kilowatt-hours exported

CRexp = credit for energy export (from previous billing period)

~~(41)~~(42) "Net Metering Program"- means the Basic Net Metering Program established in Act 114-2007; the Aggregate Net Metering Program established by the Energy Bureau's Amended Order CEPR-MI-2014-0001; and the Shared Net Metering Program established by the Energy Bureau's Amended Order CEPR-MI-2014-0001. The rules for these programs are described in -Article 7 of this Regulation.

~~(42)~~(43) "Net Metering System" – means a Generating Facility based on one or more Renewable Energy Sources that participates in the Basic Net Metering Program, the Aggregate Net Metering Program, or the Shared Net Metering Program.

~~(43)~~(44) "Network Upgrades" – means additions, modifications, and upgrades to the Transmission System to accommodate the interconnection. Network Upgrades are at or beyond the Point of Common Coupling. Network Upgrades do not include Distribution Upgrades.

~~(44)~~(45) "Non-Export" or "Non-Exporting" - means the Generating Facility or Microgrid is sized and designed using any of the methods identified for non-export in Section 1.47~~Section 5.12~~1.47 and Section 1.47.A~~Section 5.12~~1.47.A, such that the output is used for Host Load only and no electrical energy (except for any Inadvertent Export) is transferred from the Generating Facility or Microgrid to the Electric Power System.

~~(45)~~(46) "Operating Profile" - means how the Generating Facility or Microgrid is designed to be operated, as designated in the

Interconnection Application, including the amount of export, the times of year, hours of the day and other relevant conditions.

~~(46)~~(47) "Operator" – means any natural or legal person responsible for the interconnection, operation, and/or maintenance of a Generating Facility.

~~(47)~~(48) "Parallel Operation" – means the simultaneous operation of the Generating Facility or Microgrid such that power can be transferred across the Point of Common Coupling from or to the Electric Power System. This is also referred to as operating in "grid connected" mode, operating in parallel, or paralleling.

~~(48)~~(49) "Party" or "Parties" – means the Electric Power System Operator and the Interconnection Customer, individually or collectively, as applicable.

~~(49)~~(50) "Point of Common Coupling" or "PCC" – means the point of connection between the Generating Facility or Microgrid and the Electric Power System.

~~(50)~~(51) "Power Control System" – means systems or devices which electronically limit or control the steady state AC currents, or DC currents, to a programmable limit or level.

~~(51)~~(52) "Puerto Rico Electric Power Authority" or "PREPA" – means the Puerto Rico Electric Power Authority, a corporate entity created by virtue of Act No. 83 of May 2, 1941, as amended, known as the *Puerto Rico Electric Power Authority Act* ("Act 83-1941"), and any of its affiliates or subsidiaries.

~~(52)~~(53) "Pre-Application Report" – means the report issued by the EPS Operator under Section 1.22~~Section 2.05~~1.22 of this Regulation.

~~(53)~~(54) "Queue Position" – means the sequential order of a valid Interconnection Application, relative to all other pending valid Interconnection Applications, that is established based upon the date and time of receipt of the valid Interconnection Application by the EPS Operator.

~~(54)~~(55) "Reasonable Efforts" – means regarding an action required to be attempted or taken by a Party under this Regulation, efforts timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

~~(55)~~(56) "Renewable Energy Source" – means continuously renewing sources, including but not limited to solar, wind and geothermal, renewable biomass and its derivatives, hydroelectric, hydrokinetic and renewable marine, thermal ocean, municipal waste conversion, combustion of gas derived from a sanitary fill system, anaerobic digestion, and fuel cells. This definition also includes alternate renewable and sustainable renewable energy, as defined in Act 82-2010, as amended.

~~(56)~~(57) "Return to Service" – means the reentry into service following recovery from a Trip.

~~(57)~~(58) "Shared Net Metering Program" – means the extension of the Basic Net Metering Program, created as fulfillment of the Puerto Rico Energy Bureau's Amended Order CEPR-MI-2014-0001. This permits the use of renewable energy produced by a single Generating Facility based on Renewable Energy Sources between multiple participants whose service agreements are within ~~the~~or at the same location as the Generating Facility, as long as it meets the conditions established in Article 7, Section 7.04 of this Regulation.

~~(58)~~(59) "Simplified Process" – means the expedited procedure for evaluating an Interconnection Application available to small inverter-based systems that interconnect to the Distribution System. The eligibility requirements are found in Section 1.27.C~~Section 3.01~~~~1.27.C~~ and a sample form of the Simplified Interconnection Application and Agreement is found in ATTACHMENT 2. The Simplified Process uses the Fast Track screens found in Section 1.28.B~~Section 3.02~~~~1.28.B~~ with a more expedited timeline, as described in Section 1.28.A(1)~~Section 3.02~~~~1.28.A(1)~~, and simplified testing requirements, as described in Section 1.41.D~~Section 5.06~~~~1.41.D~~.

~~(59)~~(60) "Study Process" – means the procedure for evaluating an Interconnection Application that includes the scoping meeting, the system impact study, and the facilities study established under ~~Article 4~~ of this Regulation.

(61) "Technical Interconnection Requirements (TIR)" means a handbook to be prepared by the EPS pursuant to Section 1.48 of this Regulation which shall address, among other matters indicated in Section 1.48: (a) responsibilities of the Interconnecting Customer (IC) related to the grid integration, point of connection, and general system performance; (b) operational performance, power quality, protection, monitoring, control, and telemetry requirements; (c) interoperability with other grid equipment as well as metering, commissioning test and verification requirements; and specific operating requirements and any special protection that may be required for connections on radial or network locations in the distribution grid.

~~(60)~~(62) "Transmission System" – means the facilities used to provide subtransmission (38kV) and transmission (115kV) service.

~~(61)~~(63) "Trip" – means inhibition of immediate Return to Service, which may involve disconnection. Trip executes or is subsequent to Cessation of Energization.

~~(62)~~(64) "Unintentional Island" – means an unplanned Island event.

~~(63)~~(65) "Upgrades" – means the required additions and modifications to the Electric Power System. For an application to interconnect, Upgrades must be at or on the Electric Power System side of the Point Common Coupling. Upgrades may be Network Upgrades or Distribution Upgrades. Upgrades do not include Interconnection Facilities.

~~(64)~~(66) "Voltage Flicker" - means a voltage fluctuation or instability in the EPS that can cause changes in lighting, damage equipment, or that may adversely affect the quality of customer's electric service.

SECTION 1.10. Controlling Version

Should any discrepancy between the Spanish version and the English version of this Regulation arise, the English version shall prevail.

SECTION 1.11. Severability

If any article, provision, word, sentence, paragraph, subsection, or section of this Regulation is disputed before a court and declared unconstitutional or null and void, such ruling shall not affect, damage, or invalidate the remaining provisions of this Regulation, rather the effect shall be limited to the article, provision, word, sentence, paragraph, subsection, or section declared unconstitutional or null and void. The nullity or invalidity of any article, word, sentence, paragraph, subsection, or section, in any specific case, shall not affect or jeopardize in any way its application or validity in any other case, unless it has been specifically and expressly invalidated for all cases.

SECTION 1.12. Cyber Portal and Forms

The EPS Operator shall commence the operations of the Cyber Portal required under this Regulation on or before ~~ninety (90~~three hundred and sixty (360) calendar days from the effective date of this Regulation. Until the commencement of operations of the Cyber Portal, the filing, processing and notification of any document required under this Regulation will be executed by the Parties using Cyber Portal existing at the time of adoption of this Regulation, to the extent practical and via electronic mail and digital files (i.e., in PDF format~~)~~) if necessary.

The Energy Bureau, with the recommendation of the EPS Operator, shall establish the forms (printed or electronic) it deems necessary to conduct the proceedings pursuant to this Regulation and shall timely inform the public via its website and/or the EPS Operator's website, as applicable. ~~Consistent with the foregoing, the EPS Operator shall submit for the Energy Bureau's evaluation and approval the Cyber Portal before its commencement of operations. The~~The fact that the Energy Bureau has not approved or adopted one or more forms, including the Cyber Portal, is reviewing them, or the Internet website is out of service, shall relieve no party of its obligation to comply with the provisions stated, provide the information required by this Regulation, or otherwise comply with any Energy Bureau Order. Accordingly, these forms will be proposed by the EPS Operator to the Energy Bureau, and will be adopted as reviewed and approved by the Energy Bureau, and may be revised from time to time as proposed by the EPS Operator, subject to the review and approval of the Energy Bureau.

Commented [A3]: These are needed prior to the design (or redesign) of the portal.

Suggest using this opportunity to try to simplify and/or reduce all the forms or attachments needed. Only a few pertain to the safety and reliability of the grid.

Commented [A4]: The EPS responsibility is to continuously improve portals and platforms that interface customers. It is not the best practice for every improvement to be approved by regulatory body. EPS shall take reasonable actions within its responsibility mindful of the cost to make its services better for interconnection customers.

SECTION 1.13. Mode of Submission

The forms, documents, and appearances required by this Regulation or any Order of the Energy Bureau must be submitted before the ~~Energy Bureau or the~~ EPS Operator, as applicable in electronic format according to the instructions which, from time to time, the Energy Bureau and the EPS Operator publish in their respective websites.

If the electronic filing system is temporarily not operating or functioning, the forms, documents, and appearances required by this Regulation or by any Order of the Energy Bureau shall be submitted before the Energy Bureau in accordance with any instructions the Energy Bureau shall provide through an Order from time to time.

SECTION 1.14. Effect of Submission

In filing any document before the Energy Bureau or the EPS Operator, the party undersigning such document shall be deemed to have certified that the content of the document is true and that, according to the signer's best knowledge, information, and belief, formed after reasonable inquiry, the document is based on reliable and trustworthy facts, arguments, judicial sources, and information.

SECTION 1.15. Confidential Information

If in compliance with the provisions of this Regulation or any of the Energy Bureau's Orders, a Party has the duty to disclose information to the Energy Bureau considered to be confidential, a commercial or industrial secret under Act 80-2011, known as the *Puerto Rico Trade Secrets Act*, or privileged, pursuant to applicable evidentiary privileges, said Party shall identify the alleged privileged information and request in writing for the Energy Bureau to treat such information as confidential, pursuant to Article 6.15 of Act 57-2014. In identifying privileged information and requesting confidential treatment by the Energy Bureau, the requesting party shall follow the rules and procedures established by the Energy

Bureau in Resolution CEPR-MI-2016-0009[2], as such resolution may be amended from time to time, for the filing, handling, and treatment of confidential information. Except with information protected under the attorney-client privilege, the claim of confidential treatment shall, under no circumstances, be grounds for denying such information from being filed with the Energy Bureau.

SECTION 1.16. Validity

Pursuant to Section 2.8 of LPAU, this Regulation shall enter into effect thirty (30) days after its submission to the Puerto Rico Department of State and the Legislative Library of the Office of Legislative Services.

SECTION 1.17. Compliance with Other Applicable Legal Requirements

Compliance with this Regulation shall relieve no Party affected by this Regulation from complying with other applicable legal and regulatory requirements enforced by any other Government Entity.

INTERCONNECTION APPLICATION PROCESS

SECTION 1.18. Process Overview

A. Generating Facilities and Microgrids may apply to interconnect to the Distribution System or Transmission System.

B. The quickest path to interconnection is the Simplified Process, which is available to small inverter-based systems that interconnect to the Distribution System. The eligibility requirements for the Simplified Process are found in Section 1.27.C~~Section 3.011.27.C~~. Both the Simplified Process and the Fast Track Process use the screens found in Section 1.28.B~~Section 3.021.28.B~~, however the Simplified Process expedites the screening timeline, as described in Section 1.28.A(1)~~Section 3.021.28.A(1)~~ and relies on a combined application and agreement in ATTACHMENT 2.

C. The Fast Track Process is available to an Interconnection Customer proposing to interconnect a certified system with the Distribution System, if the proposed interconnection does not exceed the size limits and other eligibility requirements identified in Section 1.27.A~~Section 3.011.27.A~~. The Fast Track Process includes the optional supplemental review.

D. An application to interconnect that does not meet the eligibility requirements of Section 1.27~~Section 3.011.27~~, or does not pass the Fast Track Process, shall be evaluated under the Study Process in ~~Article 4.~~Article 4. The Study Process

[2] *See*, In re: Policy on Management of Confidential Information in Procedures Before the Commission, Case No.: CEPR-MI-2016-0009, August 31, 2016.

may include a feasibility study, a system impact study, a Transmission System impact study, and a facilities study.

E. Microgrids with an ~~Export~~Nameplate Capacity above five (5) MW must apply to interconnect to the Transmission System and must be approved by the Bureau in a process that includes citizen participation in Section 1.37~~Section 5.02~~1.37.

Commented [A5]: LUMA suggests using Nameplate Capacity; the export can be small but the Nameplate can be large. If it is interconnected to the system—in parallel, it has its effect on the system. There is a large percentage of distribution feeders at 4.16 kV, this may considerably limit the capacity of systems connected to those feeders.

SECTION 1.19. Pre-Application Report and Interconnection Application Filing Mechanisms

Interconnection Customers shall submit all Pre-Application Report requests and Interconnection Applications through the Cyber Portal.

SECTION 1.20. Electronic Signatures

All required applications, agreements and forms must be signed using electronic signatures.

SECTION 1.21. Communications

A. The EPS Operator shall designate an Interconnection Coordinator(s) and this person or persons shall serve as a single point of contact from which information on the status of an application process can be obtained~~ through informal requests from the Interconnection Customer presenting a proposed project for a specific site.~~, other than the information provided by the Cyber Portal.

Commented [A6]: LUMA has centralized its Customer Experience and interaction process to be in line with best practices. Multiple points of contact causes confusion for customers and does not allow for efficiencies within the organization. LUMA suggests it be allowed to organize its organization in a way to best meet customer needs. LUMA is incorporating DG information and protocols into its Customer Contact center.

Given the volume of applications, this will require a team and management of such team and therefore significantly more costs. Costs need to be incorporated into the costs to be charged to the Interconnection Customer as to avoid subsidization by non-participating customers. Additionally, costs associated with this requirement is not part of the currently approved budget and as such will require a budget amendment

B. The name, telephone number, and e-mail address of such contact employee or office shall be made available on the EPS Operator's website.

C. The EPS Operator may have several Interconnection Coordinators assigned, based on the geographical size of its electrical service territory and/or the amount of Interconnection Applications.

D. The Interconnection Coordinator(s) shall be available to answer questions, connect Interconnection Customers with persons who can address and resolve questions, and otherwise help facilitate communication with the EPS Operator about the status of the Interconnection Application.

E. Upon request, EPS information provided to the Interconnection Customer should include materials useful to an understanding of an interconnection at a particular point on the EPS, including system studies, interconnection studies, workpapers, and supporting documentation (*i.e.*, relevant power flow, short circuit and stability databases), to the extent such provision does not violate confidentiality provisions of prior agreements or critical infrastructure requirements.

~~F. Upon request of either party, the EPS Operator and the Interconnection Customer shall each identify one (1) point of contact with technical expertise for their respective organizations.~~

~~Upon the request of either party, status calls could be established every other week.~~

SECTION 1.22. Pre-Application Requests and Reports

A. Besides the information described in Section 1.21~~Section 2.041.21~~, which may be provided in response to an informal request, an Interconnection Customer may submit a formal written request form along with a non-refundable fee ~~of three hundred dollars ($300.00~~to be proposed by the EPS Operator to the Energy Bureau, as reviewed and approved by the Energy Bureau (which may be revised from time to time if justified and subject to the review and approval of the Energy Bureau) for a Pre-Application Report on a proposed project at a specific site.

B. The EPS Operator shall provide the Pre-Application Report described in Section 1.22.G~~Section 2.051.22.G~~ to the Interconnection Customer within ~~fifteen (15~~an average of (30) Business Days of receipt of the completed request form and ~~payment of~~ the ~~$300~~ non-refundable fee stated in Section 1.22.A.

C. The Pre-Application Report produced by the EPS Operator is non-binding, confers no rights, and the Interconnection Customer must still apply to interconnect to the Electric Power System.

D. The written Pre-Application Report request form shall include the information in Section 1.22.E~~Section 2.051.22.E~~ below to clearly and sufficiently identify the location of the proposed Point of Common Coupling.

E. The Pre-Application Report request shall include the following information:

(1) Project contact information, including name, address, phone number, and email address;

(2) Project location (street address(es) with nearby cross streets and town, or place registered with the Property Registry Office);

(3) Meter number, pole number, or other equivalent information identifying proposed Point of Common Coupling(s), if available;

(4) For Microgrids, Microgrid type (*e.g.*, Personal, Cooperative, Third-Party);

(5) Generator type(s) (*e.g.*, solar, wind, combined heat and power, etc.);

Commented [A7]: The use of an average time requirement here and throughout allows for the unavoidable occurrence of complex cases that will extend beyond the time limit, while ensuring that the majority of cases meet time requirements. This data could be extracted from Web Portal. This is a concept that has been used in other jurisdictions.

Commented [A8]: This is a new report and process that will take time to develop and integrate with the Portal's architecture and broader IT system.

(6) Nameplate Rating and Export Capacity (*i.e.*, alternating current kW);

(7) Single or three phase generator configuration; and

(8) Whether new service is requested. If there is existing service, include the customer account number(s), site minimum, and maximum current or proposed electric loads in kW (if available) and specify if the load is expected to change.

F. Using the information provided in the Pre-Application Report request form, the EPS Operator will use best efforts to identify the substation/area bus, bank, or circuit likely to serve the proposed Point of Common Coupling . This selection by the EPS Operator does not necessarily indicate, after application of the screens and/or study, this would be the circuit the project ultimately connects to. The Interconnection Customer must request additional Pre-Application Reports if information about multiple Points of Common Coupling is requested. If any information required to be provided to the Interconnection Customer is considered Confidential Information, then the Interconnection Customer will be required to sign a Non-Disclosure Agreement in order to receive the required information.

G. Subject to Section 1.22.H~~Section 2.051.22.H~~, the Pre-application Report shall include the following information, if available:

(1) Total capacity (in megawatts (MW)) of substation/area bus, bank or circuit based on normal or operating ratings likely to serve the proposed Point of Common Coupling .

(2) Existing aggregate Nameplate Rating and Export Capacity (in MW) interconnected to a substation/area bus, bank or circuit (*i.e.*, amount of generation online) likely to serve the proposed Point of Common Coupling .

(3) Aggregate queued Nameplate Rating and Export Capacity (in MW) for a substation/area bus, bank or circuit (*i.e.*, amount of generation in the queue) likely to serve the proposed Point of Common Coupling .

(4) Available Nameplate Rating and Export Capacity (in MW) of substation/area bus or bank and circuit likely to serve the proposed Point of Common Coupling (*i.e.*, total capacity less the sum of existing aggregate Export Capacity and aggregate queued Export Capacity).

(5) Substation nominal distribution voltage and/or transmission nominal voltage if applicable.

(6) Nominal circuit voltage at the proposed Point of Common Coupling~~-~~.

(7) Approximate circuit distance between the proposed Point of Common Coupling and the substation.

(8) Relevant line section(s) actual or estimated peak load and minimum load data, including daytime minimum load as described in Section 1.30.C(1)~~Section 3.04~~1.30~~.C(1)~~ below and absolute minimum load, when available.

(9) Number, type and rating of protective devices, and number, type and rating (standard, bi-directional) of voltage regulating devices between the proposed Point of Common Coupling and the substation/area. Identify whether the substation has a load tap changer.

(10) Number of phases available at the proposed Point of Common Coupling. If only a single phase is available, specify the distance from the three-phase circuit.

(11) Limiting conductor ratings from the proposed Point of Common Coupling to the distribution substation.

(12) Whether the Point of Common Coupling is located on a spot network, grid network, or radial supply.

(13) Based on the proposed Point of Common Coupling~~-~~, existing or known constraints such as, but not limited to, electrical dependencies at that location, short circuit interrupting capacity issues, power quality or stability issues on the circuit, capacity constraints, or secondary networks.

H. The Pre-Application Report need only include existing data. A Pre-Application Report request does not bind the EPS Operator to conduct a study or other analysis of the proposed generator in the event that data is not readily available. If the EPS Operator cannot complete all or some of a Pre-Application Report due to lack of available data, the EPS Operator shall provide the Interconnection Customer with a Pre-Application Report that includes the data that is available and shall list what additional data is not provided, if any. The provision of information on "available capacity" pursuant to Section 1.22.G(4)~~Section 2.05~~1.22~~.G(4)~~ does not imply that an interconnection up to this level may be completed without impacts since there are many variables studied as part of the interconnection review process, and data provided in the Pre-Application Report may become outdated at the time of the submission of the complete Interconnection Application. Notwithstanding the provisions of this section, the EPS Operator shall, in good faith, include data in the Pre-Application Report that represents the best available information at the time of reporting.

SECTION 1.23. Submittal of the Interconnection Application

A. The Interconnection Customer shall submit its Interconnection Application ~~(ATTACHMENT 1)~~ or Simplified Interconnection Application and Agreement ~~(ATTACHMENT 2)~~ to the EPS Operator, together with the applicable processing fee or deposit specified in the Interconnection Application. Additional fees or deposits shall not be required, except as otherwise specified in this Regulation or by an Energy Bureau Order. The Interconnection Application shall contain, at a minimum, the information indicated in the sample form in Attachment 1 and the Simplified Interconnection Application and Agreement shall contain, at a minimum, the information indicated in the sample form in Attachment 2. The EPS Operator may prepare proposed revised versions of the Interconnection Application and the Simplified Interconnection Application and Agreement which shall be submitted for review of the Energy Bureau and will be implemented if and as approved by the Energy Bureau.

Commented [A9]: The regulation should specify that the information required within the Interconnection Application be approved by the Energy Bureau instead of including the Interconnection Application forms in the regulation. This will allow for adjustments, improvements to the Interconnection Applications (to reflect findings and changes in technology) to occur without having to complete the process of amending a regulation, provides the Energy Bureau oversight without undue regulatory burden for both the Energy Bureau and the EPS Operator and allows processes to modernize and improve in a more timely manner.

Regulation should only specify content to be collected and not specify form or formatting as these currently appear to be made for paper / pdf Application, not digital.

B. The EPS Operator shall keep record of submission dates and times. The original submission date and time of the completed Interconnection Application shall be ~~date- and time-stamped upon receipt. The original date- and time-stamp applied to the Interconnection Application at the time of its original submission shall be~~ accepted as the qualifying date~~-~~ and time~~-stamp~~ for the purposes of any timetable in this Regulation as described in Section 1.26.

C. The Interconnection Customer shall be notified of receipt by the EPS Operator within one (1) Business Day of receiving the Interconnection Application; this may be an automatic e-mail that includes the date and time stamped on the Interconnection Application.

D. For Interconnection Customers using the Simplified Interconnection Application and Agreement, the EPS Operator shall notify the Interconnection Customer within ~~three (3~~an average of five (5) Business Days of receiving the Simplified Interconnection Application whether the Simplified Interconnection Application is complete. If the Interconnection Application is incomplete, the EPS Operator shall provide, along with the notice that the Interconnection Application is incomplete, a written list detailing all information that must be provided to complete the Interconnection Application. The Interconnection Customer will have five (5) Business Days after receipt of the notice to submit the listed information. The EPS Operator shall review the additional material and notify the Interconnection Customer that the Interconnection Application is complete within ~~three (3~~an average of five (5) Business Days. If the Interconnection Customer does not provide the listed information within the deadline, the Interconnection Application will be deemed withdrawn.

Commented [A10]: Keep both the simplified and other applications at the same length of time for review (5 days) – it is a small difference and it will be much easier to have one review time period for all.

E. For Interconnection Customers using the Interconnection Application, the EPS Operator shall notify the Interconnection Customer within an average of five (5) Business Days of receiving the Interconnection Application whether the

Interconnection Application is complete. If the Interconnection Application is incomplete, the EPS Operator shall provide, along with the notice that the Interconnection Application is incomplete, a written list detailing all information that must be provided to complete the Interconnection Application. The Interconnection Customer will have ten (10) Business Days after receipt of the notice to submit the listed information. The EPS Operator shall have an additional ~~three (3~~five (5) Business Days on average to review the additional material and notify the Interconnection Customer that the Interconnection Application is complete. If the Interconnection Customer does not provide the listed information within the deadline, the Interconnection Application will be deemed withdrawn.

F. An Interconnection Application will be deemed complete upon the correct and complete submission of all of the listed information or documentation to the EPS Operator.

SECTION 1.24. Modification of the Interconnection Application

A. At any time, including after receiving Simplified Process, Fast Track, supplemental review, feasibility, system impact, and/or facilities study results, the Interconnection Customer or the EPS Operator may identify modifications to the planned interconnection that may improve the costs and benefits (including reliability) of the interconnection, and/or the ability of the EPS Operator to accommodate the interconnection. The Interconnection Customer shall submit to the EPS Operator, in writing, all proposed modifications to any information provided in the Interconnection Application.

B. Within an average of ten (10) Business Days of receipt of a proposed modification, the EPS Operator shall evaluate whether a proposed modification constitutes a Material Modification.

C. If the proposed modification is determined to be a Material Modification, then the EPS Operator shall notify the Interconnection Customer in writing that the Interconnection Customer may: (1) withdraw the proposed modification; or (2) proceed with a new Interconnection Application for such modification. The Interconnection Customer shall notify the EPS Operator of its determination in writing within an average of ten (10) Business Days after being provided the Material Modification determination results. If the Interconnection Customer does not provide its determination, the Interconnection Customer's Application shall be deemed withdrawn.

D. If the proposed modification is determined not to be a Material Modification, then the EPS Operator shall notify the Interconnection Customer in writing that the modification has been accepted and that the Interconnection Customer shall retain its eligibility for interconnection, including its place in the interconnection queue.

E. Any dispute as to the EPS Operator's determination that a modification constitutes a Material Modification shall proceed in accordance with Article 8 of this Regulation.

F. Any modifications to an Interconnection Application not agreed to in writing by the EPS Operator and the Interconnection Customer may be deemed a withdrawal of the Interconnection Application and may require submission of a new Interconnection Application.

SECTION 1.25. Site Control

The Interconnection Application must include evidence of site control. Site control may be demonstrated through the following:

A. ~~Ownership~~Documents that show ownership of, a leasehold interest in, or a right to develop a site or sites for the purpose of constructing the Generating Facility or Microgrid~~;~~, which must be one of the following: a deed of purchase, a lease agreement, a purchase agreement, an option to purchase or lease, a concession or a license.

~~B. An option to purchase or acquire a leasehold site(s) for such purpose; or~~

~~C. An exclusivity or other business relationship between the Interconnection Customer and the entity having the right to sell, lease, or grant the Interconnection Customer the right to possess or occupy a site(s) for such purpose.~~

SECTION 1.26. Queue Position

A. The EPS Operator shall assign a Queue Position based upon the date - and time-stamp of the complete Interconnection Application.

B. The Queue Position of each Interconnection Application will be used to determine the cost responsibility for the Upgrades required to accommodate the interconnection. The EPS Operator shall maintain a single sequential queue. Although applications are processed in the order received, some applications may be processed in parallel where applications are in different locations and do not impact each other. Also, some applications may take longer to process, so later applications may be processed during that time, as long as they do not negatively impact the application taking longer to process.

C. Subject to the provisions of Section 1.23~~Section 2.06~~1.23, Section 1.24~~Section 2.07~~1.24, and Section 1.25~~Section 2.08~~1.25, Interconnection Customers shall retain the Queue Position assigned to their initial Interconnection Application throughout the review process~~, including when moving through the processes covered by Article 3 and Article 4.~~.

D. If a Generating Facility has a prior Queue Position and is now seeking to join or convert to a Microgrid then the prior Queue Position will be abandoned in favor of the Queue Position of the Microgrid. Queue position shall not be transferred to a different proponent, project or application.

DISTRIBUTION SYSTEM FAST TRACK PROCESS

SECTION 1.27. Applicability and eligibility requirements

The Simplified Process and Fast Track Process are available to an Interconnection Customer proposing to interconnect with the Distribution System if the proposed interconnection does not exceed the size limits and other requirements identified in ~~this~~ Section 1.27~~Section 3.011.27~~. However, eligibility is distinct from the Fast Track Process itself, and eligibility does not imply or indicate that an Interconnection Application will pass the Fast Track screens in Section 1.28~~Section 3.021.28~~ or the supplemental review screens in Section 1.30~~Section 3.041.30~~.

The Simplified Process is available to Interconnection Customers whose proposed interconnection meets both the eligibility requirements for the Fast Track process found in Section 1.27.A~~Section 3.011.27.A~~ and the smaller size requirements for the Simplified Process found in Section 1.27.C~~Section 3.011.27.C~~. Both the Simplified Process and the Fast Track Process use the screens found in Section 1.28.B~~Section 3.021.28.B~~, however the Simplified Process expedites the screening timeline, as described in Section 1.28.A(1)~~Section 3.021.28.A(1)~~. The Simplified Interconnection Application and Agreement includes a standard interconnection agreement, therefore if the proposed interconnection passes the screens, the EPS Operator returns an executed Interconnection Agreement to the Interconnection Customer as described in Section 1.28.A(1)~~Section 3.021.28.A(1)~~.

A. Fast Track Eligibility

An Interconnection Application is eligible for Fast Track if the proposed interconnection includes:

(1) A single Point of Common Coupling;

(2) A Point of Common Coupling on a radial distribution circuit, or a spot network serving one customer;

(3) No more than one service drop;

(4) Only certified Generating Facilities~~;~~ (as per requirements of Attachment 4); and

(5) Has an Nameplate Rating under the thresholds found in Table 1~~Table 1~~ below.

Table 1: Fast Track Eligibility Size Limit

Line Voltage	Nameplate Rating Regardless of Location
< 5 kV	≤ 500 kW
≥ 5 kV and < 15 kV	≤ 1 MW

B. In addition to the requirements of Section 1.27~~Section 3.011.27~~, the proposed interconnection must meet the technical requirements in ~~Article 6 as well as the~~the Technical Interconnection Requirements document which will include the applicable codes, standards, and certification requirements~~ of ATTACHMENT 4 of this Regulation~~. Alternatively, if the proposed interconnection varies from those requirements, the EPS Operator may review the design and/or test the proposed interconnection to ensure it is safe to operate.

C. Simplified Process Eligibility

The Simplified Process is available to Interconnection Customers who submit the Simplified Interconnection Application and Agreement, and whose proposed interconnection meets the eligibility requirements for the Fast Track process found in Section 1.27.A~~Section 3.011.27.A~~ and use inverter-based Generating Facilities with: a Nameplate Rating of 50 kW or less, and an Export Capacity of 25 kW or less.

The EPS Operator shall use the expedited timelines for the Simplified Process described in Section 1.28.A(1)~~Section 3.021.28.A(1)~~.

SECTION 1.28. Initial Review.

A. Screening Timeline

The EPS Operator shall perform an initial review of the Interconnection Application using the Fast Track screens set forth below and shall notify the Interconnection Customer of the initial review results, and include with the notification copies of the analysis and data underlying the EPS Operator's determinations under the screening requirements.

(1) For the Simplified Process, the EPS Operator shall provide these results within ~~seven (7~~an average of fifteen (15) Business Days after notifying the Interconnection Customer it has received a complete Simplified

Commented [A11]: These limits might be changed, pending additional revision of Technical Interconnection Requirements document.

Formatted: Check spelling and grammar

Commented [A12]: Current regulation (8915) establishes a Fast-track process for DG systems up to 1 MW for all distribution voltages; however, there are other eligibility criteria (including distance from substation, conductor size, etc. - section IV Article D.3 of regulation 8915) that further filter applications based on technical requirements. These other requirements should be included in the proposed regulation as additional screening criteria. We suggest including the additional screening criteria included in 8915.

Interconnection Application and Agreement. If the proposed interconnection passes the screens, the EPS Operator shall countersign the Simplified Interconnection Application and Agreement and provide the executed interconnection agreement to the Interconnection Customer when it provides the results of the screens.

(2) For Interconnection Customers using the Interconnection Application, the EPS Operator shall provide these results within an average of fifteen (15) Business Days after notifying the Interconnection Customer it has received a complete Interconnection Application.

B. Fast Track Screens:

(1) For interconnection to a radial distribution circuit, the aggregated Export Capacity, including the proposed Generating Facility or Microgrid, on the circuit shall not exceed fifteen percent (15%) of the line ~~section~~or feeder annual peak load as most recently measured at the substation~~. A line section is that portion of the Distribution System connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line. This screen does not apply to a Non-Exporting Generating Facility or Non-Exporting Microgrid, or existing facilities proposing to add no new Export Capacity~~.

Commented [A13]: This requirement confuses line section with total feeder measured at the substation terminal.

Eventually the 15% test will be meaningless since there will be a lot of load masking, at which time the use of Minimum Daytime Load will be much more meaningful.

In either case, the reviewer must take any added Generation that has gone active or is pending since the time of the 15% calculation or MDL measurement to bring the evaluation up to date and make it meaningful.

Suggest the flexibility to use MDL when that becomes a feasible screening criteria to implement.

~~(2) For interconnection to the load side of spot network protectors, the proposed interconnection must utilize an inverter-based equipment package and, the Nameplate Rating of the Generating Facility or Microgrid, together with the aggregated other inverter-based generation, shall not exceed the smaller of five percent (5%) of a spot network's maximum load or 50 kW.[3]~~

~~(3)~~(2) The Nameplate Rating of the proposed Generating Facility or Microgrid, in aggregate with the Nameplate Rating of other generation on the distribution circuit, shall not contribute over ten percent (10%) to the distribution circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed Point of Common Coupling. The EPS Operator may allow Generating Facilities or Microgrids with a Nameplate Rating of 50 kW or less to skip this screen.

~~(4)~~(3) The Nameplate Rating of the proposed Generating Facility or Microgrid, in aggregate with the Nameplate Rating of other generation on the distribution circuit, shall not cause any distribution protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or Interconnection

~~[3] A spot network is a type of distribution system found within modern commercial buildings to provide high reliability of service to a single customer. See STANDARD HANDBOOK FOR ELECTRICAL ENGINEERS, 11th Edition, Donald Fink, McGraw Hill Book Company.~~

Customer equipment on the system to exceed ninety (90%) of the short circuit interrupting capability; nor shall the interconnection be proposed for a circuit that already exceeds ninety percent (90%) of the short circuit interrupting capability. The EPS Operator may allow Generating Facilities or Microgrids with a Nameplate Rating of 50 kW or less to skip this screen.

~~(5)~~(4) Using the ~~table below,~~applicable criteria in the TIR, determine the type of interconnection to a primary distribution line. This screen includes a review of the type of electrical service provided to the Interconnection Customer, including line configuration and the transformer connection to limit the potential for creating over-voltages on the EPS due to a loss of ground during the operating time of any anti-islanding function.

This screen does not apply to Generating Facilities or Microgrids with a Nameplate Rating of 50 kW or less.

~~**Primary Distribution Line Type**~~	~~**Type of Interconnection**~~	~~**Result/Criteria**~~
~~Three-phase, three wire~~	~~Any type~~	~~Pass screen~~
~~Three-phase, four wire~~	~~Single-phase, line-to-neutral~~	~~Pass screen~~
~~Three-phase, four wire~~	~~Effectively-grounded three-phase~~	~~Pass screen~~
~~Three-phase, four-wire~~	~~All other types~~	~~Pass screen if the Nameplate Rating of the proposed Generating Facility or Microgrid, in aggregate with the Nameplate Rating of other generation on the line section, is less than or equal to ten (10) percent of line section peak load~~
~~Three-phase, four-wire~~	~~All other types~~	~~To pass the screen when the Nameplate Rating of the proposed Generating Facility or Microgrid, in aggregate with the Nameplate Rating of other generation on the line section, is greater than ten~~

Commented [A14]: The criteria referenced in the table below might change, as the TIR is updated and completed.

Commented [A15]: Need to determine how the customer will provide evidence of effective grounding, since it depends on the combination inverter-based generation and system topology. Effective grounding can only be determined after a study that demonstrate a certain level of voltage rise. This is the type of policy that should be included in an accompanying Technical Interconnection Requirements Document.

~~Primary Distribution Line Type~~	~~Type of Interconnection~~	~~Result/Criteria~~
		~~(10) percent of line section peak load, the Generating Facility or Microgrid must be inverter-based and not prone to support ground fault overvoltage at the PCC~~

~~(6)~~(5) If the proposed interconnection is on single-phase shared secondary, the aggregate Export Capacity on the shared secondary, including the proposed Generating Facility or Microgrid, shall not exceed sixty five percent (65%) of the transformer nameplate rating.

~~(7)~~(6) If the proposed interconnection is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of over 20% of the nameplate power rating of the service transformer.

~~(8)~~(7) The Nameplate Rating of the Generating Facility or Microgrid, in aggregate with other generation interconnected to the transmission side of a substation transformer feeding the circuit where the Microgrid proposes to interconnect shall not exceed 10 MW in an area where there are known, or posted, transient stability limitations to generating units located in the general electrical vicinity (*e.g.*, three (3) or four (4) transmission busses from the Point of Common Coupling).

C. Notifications and Execution of Applicable Agreements

If the proposed interconnection passes the screens, or if the proposed interconnection fails the screens, but the EPS Operator determines that the proposed interconnection may nevertheless be interconnected consistent with safety, reliability, and power quality standards, the Interconnection Application shall proceed as follows:

(1) For the Simplified Process, if the proposed interconnection requires construction of facilities or upgrades, it shall be treated like other Fast Track projects and follow the procedures below and be asked to sign the Interconnection Agreement in Attachment 8~~Attachment 8~~.

(2) If the proposed interconnection does not use the Simplified Process and requires no construction of facilities on the Electric Power System, the EPS Operator shall provide the Interconnection Customer an

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executed Interconnection Agreement within ~~five (5~~ an average of fifteen (15) Business Days after the determination.

(3) If the proposed interconnection requires only Minor System Modifications, the EPS Operator shall notify the Interconnection Customer of such requirement when it provides initial review results and copies of the analysis and data underlying the determinations under the screens. Within five (5) Business Days, the Interconnection Customer must inform the EPS Operator if the Interconnection Customer elects to continue the Application. If the Interconnection Customer makes such an election, the EPS Operator shall provide an Interconnection Agreement, along with a non-binding good faith cost estimate and construction schedule for such upgrades, to the Interconnection Customer within ~~fifteen (15~~an average of thirty (30) Business Days after the EPS Operator receives such an election.

(4) If the proposed interconnection requires more than Minor System Modifications, the EPS Operator shall notify the Interconnection Customer of such requirement when it provides the initial review results and copies of the analysis and data underlying the screen determinations. Within five (5) Business Days, the Interconnection Customer must inform the EPS Operator if the Interconnection Customer elects to proceed with the proposed interconnection. If the Interconnection Customer makes such an election, the EPS Operator may elect to (i) provide an Interconnection Agreement, along with a non-binding good faith cost estimate and construction schedule for such upgrades, within ~~twenty (20~~an average of forty (40) Business Days after the EPS Operator receives such an election or (ii) notify the Interconnection Customer that an interconnection facilities study must be performed pursuant to Section 1.35~~Section 4.05~~1.35, and provide a facilities study agreement within ten (10) Business Days after the EPS Operator receives such an election.

(5) If the proposed interconnection fails the screens, and the EPS Operator cannot determine from the initial review that the proposed interconnection may nevertheless be interconnected consistent with safety, reliability, and power quality standards unless the Interconnection Customer considers minor modifications or further study, the EPS Operator shall provide the Interconnection Customer with the opportunity to attend the customer options meeting in Section 1.29~~Section 3.03~~1.29 of this Regulation.

SECTION 1.29. Customer Options Meeting

A. If the EPS Operator determines the Interconnection Application cannot be approved without (1) a supplemental study or other additional studies or actions or (2) incurring significant cost to address safety, reliability, or power quality problems, the EPS Operator shall notify the Interconnection Customer of that determination and provide ~~copies of all data and analyses underlying~~a detailed explanation supporting its conclusion.

B. If requested by the Interconnection Customer, within ten (10) Business Days of the EPS Operator's determination, the EPS Operator shall convene a customer options meeting with the Interconnection Customer and the EPS Operator.

C. At the customer options meeting, the Parties shall review the screen analysis and related results, possible Generating Facility or Microgrid modifications, and determine what further steps are needed to permit the safe and reliable interconnection.

D. At the time of notification of the EPS Operator's determination, or at the customer options meeting, the EPS Operator shall:

(1) Offer to perform a supplemental review in accordance with Section 1.30~~Section 3.04~~1.30 and provide a non-binding good faith estimate of the costs of such review; or

(2) Obtain the Interconnection Customer's agreement to continue evaluating the Interconnection Application under the Study Process in ~~Article 4.~~Article 4.

SECTION 1.30. Supplemental Review

A. To accept the offer of a supplemental review, the Interconnection Customer shall agree in writing and submit a deposit for the estimated costs of the supplemental review in the amount of the EPS Operator's good faith estimate of the costs of such review, both within an average of fifteen (15) Business Days of the offer. If the written agreement and deposit have not been received by the EPS Operator within that timeframe, the Interconnection Application shall continue to be evaluated under the ~~Article 4~~Article 4 Study Process unless it is withdrawn by the Interconnection Customer. The Interconnection Application will be deemed withdrawn if the supplemental review payment in not submitted within 90 days after receiving estimated cost of such review.

B. The Interconnection Customer shall be responsible for the EPS Operator's actual costs for conducting the supplemental review. The Interconnection Customer must pay any review costs that exceed the deposit within twenty (20) Business Days of receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced costs, the EPS Operator will return such excess within an average of twenty (20) Business Days of the invoice without interest.

C. Within an average of thirty (30) Business Days following receipt of the deposit for a supplemental review, the EPS Operator shall (1) perform a supplemental review using the screens set forth below; (2) notify in writing the Interconnection Customer of the results; and (3) include with the notification copies of the analysis and data underlying the determinations under the screens.

(1) *Minimum Load Screen*: Where 12 months of line section minimum load data (including Host Load but not station service load served by the proposed Generating Facility or Microgrid) are available, can be calculated, can be estimated from existing data, or determined from a power flow model, the aggregate Export Capacity of the Generating Facilities on the line section is less than 100% of the minimum load for all line sections bounded by automatic sectionalizing devices upstream of the proposed interconnection. If minimum load data is not available, or cannot be calculated, estimated or determined, the EPS Operator shall include the reason(s) that it is unable to calculate, estimate or determine minimum load in its supplemental review results notification under Section 1.30.D~~Section 3.041.30.D~~ This screen does not apply to a Non-Exporting Generating Facility or Non-Exporting Microgrid, or existing facilities proposing to add no new Export Capacity

(2) *Type of generation*: The type of generation used by the proposed interconnection will be considered when calculating, estimating, or determining circuit or line section minimum load relevant for applying screening requirements of Section 1.30.C(1)~~Section 3.041.30.C(1)~~. Solar photovoltaic (PV) generation systems with no Energy Storage use daytime minimum load (*i.e.*, 10 a.m. to 4 p.m. for fixed panel systems and 8 a.m. to 6 p.m. for PV systems utilizing tracking systems), while all other generation uses absolute minimum load. The EPS Operator shall apply this screen using the Operating Profile and system design designated in the Interconnection Application. For example, the EPS Operator shall evaluate the maximum Export Capacity only during the hours of the day designated by the customer as operational, and shall consider any export controls that comply with Section 1.47~~Section 5.121.47~~.

(i) Only the net injection of power into the EPS will be considered as part of the aggregate Export Capacity.

(ii) For the purposes of this screen, the EPS Operator will not consider as part of the aggregate Export Capacity any existing Export Capacity already reflected in the minimum load data.

(iii) Although export will not be considered, load reducers that are applying to interconnect, that do not export, will be considered to effectively reduce circuit or circuit section load by the amount of load the generator is displacing.

(3) *Voltage and Power Quality Screen:* In aggregate with existing generation on the line section: (1) the voltage regulation on the line section can be maintained in compliance with requirements under all system conditions; (2) the voltage fluctuation, including Rapid Voltage Change is within acceptable limits as defined by Institute of Electrical and Electronics Engineers (IEEE) Standard 1453 or Standard 1547-2018, or utility practice similar to IEEE Standard 1453 or Standard 1547-2018~~; and (3) the harmonic levels meet IEEE Standard 519 limits.[4]~~.[5]

Commented [A16]: IEEE 1547 was published in April 2018 and is in effect. The harmonic limits of 1547 do not exactly match those of 519. 519 is more suitable to aggregated load facilities while 1547 is directly applicable to DER POC. 1547 should be the prevailing standard for harmonics and RVC.

(4) *Safety and Reliability Screen:* The location of the proposed interconnection and the aggregate generation on the line section do not create impacts to safety or reliability that cannot be adequately addressed without application of the Study Process. The EPS Operator shall consider the following and other factors in determining potential impacts to safety and reliability in applying this screen.

(i) Whether the line section has significant minimum loading levels dominated by a small number of customers (*e.g.*, several large commercial customers).

(ii) Whether the loading along the line section is uniform or even.

(iii) Whether the proposed interconnection is located in close proximity to the substation (*i.e.*, less than 2.5 electrical circuit miles), and whether the line section from the substation to the Point of Common Coupling is a Mainline rated for normal and emergency ampacity.

(iv) Whether the proposed interconnection reduces operational flexibility, such that transfer of the line section(s) of the Generating Facility or Microgrid to a neighboring distribution circuit/substation may trigger overloads or voltage issues.

(v) Whether the proposed interconnection employs equipment or systems certified by recognized standards organization to

~~[4] Voltage fluctuation and harmonics limits are both addressed by IEEE 1547-2018. However, until full adoption of IEEE 1547-2018 is complete, IEEE 1453 and IEEE 519 may be used for the respective requirements. Equipment tested to comply with the updated harmonics requirements of IEEE 1547-2018 will not be available until approximately 18 months or more after publication of the revision of IEEE 1547.1.~~

[5] Voltage fluctuation and harmonics limits are both addressed by IEEE 1547-2018. However, until full adoption of IEEE 1547-2018 is complete, IEEE 1453 and IEEE 519 may be used for the respective requirements. Equipment tested to comply with the updated harmonics requirements of IEEE 1547-2018 will not be available until approximately 18 months or more after publication of the revision of IEEE 1547.1.

address technical issues such as, but not limited to, Islanding, reverse power flow, or voltage quality.

D. If the proposed interconnection passes the supplemental screens in Section 1.30.C~~Section 3.04~~1.30~~.C~~ above, or if the proposed interconnection fails the screens, but the EPS Operator determines that it may nevertheless be interconnected consistent with safety, reliability, and power quality standards, the interconnection shall proceed as follows:

(1) If the proposed interconnection passes the supplemental screens in Sections Section 1.30.C~~Section 3.04~~1.30~~.C~~ and does not require construction of facilities on the Electric Power System, the EPS Operator shall provide the Interconnection Customer an executed Interconnection Agreement at the time it provides the supplemental review results in accordance with the timeline in Section 1.30.C~~Section 3.04~~1.30~~.C~~. If using the Simplified Process, the EPS Operator shall countersign the Simplified Interconnection Application and Agreement and provide the fully executed interconnection agreement to the Interconnection Customer at the same time it provides the supplemental review results.

(2) If the proposed interconnection requires only Minor System Modifications, the EPS Operator shall notify the Interconnection Customer of such requirement when it provides supplemental review results. Within five (5) Business Days, the Interconnection Customer must inform the EPS Operator if the Interconnection Customer elects to continue. If the Interconnection Customer makes such an election, the EPS Operator shall provide an Interconnection Agreement, along with a non-binding good faith cost estimate and construction schedule for such upgrades, to the Interconnection Customer within an average of fifteen (15) Business Days after the EPS Operator receives such an election.

(3) If the proposed interconnection requires more than Minor System Modifications, the EPS Operator shall notify the Interconnection Customer of such requirement when it provides the supplemental review results. Within five (5) Business Days, the Interconnection Customer must inform the EPS Operator if the Interconnection Customer elects to proceed with the proposed interconnection. If the Interconnection Customer makes such an election, the EPS Operator may elect to (i) provide an Interconnection Agreement, along with a non-binding good faith cost estimate and construction schedule for such upgrades, within ~~twenty (20)~~ an average of 40 Business Days after the EPS Operator receives such an election or (ii) notify the Interconnection Customer that an interconnection facilities study must be performed pursuant to Section 1.35~~Section 4.05~~1.35, and provide a

facilities study agreement within an average of ten (10) Business Days after the EPS Operator receives such an election.

E. If the proposed interconnection fails the screens, and the EPS Operator does not or cannot determine that it may nevertheless be interconnected consistent with safety, reliability, and power quality standards unless the Interconnection Customer will consider minor modifications or further study, the EPS Operator shall provide the customer the option of commencing the Study Process in 0~~Article 4~~0. If the Interconnection Customer wishes to proceed it shall notify the EPS Operator within fifteen (15) Business Days to retain its queue position.

STUDY PROCESS

SECTION 1.31. Purpose

The Study Process shall be used by an Interconnection Customer proposing to interconnect with the EPS if the Interconnection Application (1) is not eligible for Fast Track Process, or (2) did not pass the Fast Track Process.

SECTION 1.32. Scoping Meeting.

A. The purpose of the scoping meeting is to discuss the Interconnection Application and review existing studies relevant to the Interconnection Application. The Parties shall further discuss whether the EPS Operator should perform feasibility study, or proceed directly to a system impact study or studies, a facilities study, or an Interconnection Agreement. If the EPS Operator ~~and Interconnection Customer~~will determine there is no potential for adverse system impacts, the Interconnection Customer shall proceed directly to a facilities study or an executable Interconnection Agreement, as agreed to by the Parties

B. A scoping meeting shall be held within ~~five (5~~ an average of (15) Business Days after the Interconnection Application is deemed complete and, if applicable, the Fast Track Process has been completed. The EPS Operator and the Interconnection Customer will bring the relevant personnel to the meeting, including system engineers and others that may be required to accomplish the purpose of the meeting.

C. The scoping meeting may be waived by agreement of the Parties.

SECTION 1.33. Feasibility Study.

A. A feasibility study shall be conducted only upon the request of the Interconnection Customer. The EPS Operator shall not require a feasibility study.

B. If the Parties mutually agree at the scoping meeting that the EPS Operator should perform a feasibility study, the EPS Operator shall provide the Interconnection Customer, as soon as possible, but not later than ~~three (3)~~ five (5) Business Days after the scoping meeting, a feasibility study agreement ~~(ATTACHMENT 5).~~ in the form proposed by the EPS Operator and approved by the Bureau.

C. If the scoping meeting is omitted ~~but the Parties agree that~~ , the EPS Operator should conduct a feasibility study if necessary, the EPS Operator shall provide the Interconnection Customer a feasibility study agreement within an average of ten (10) Business Days after the Interconnection Application is deemed complete and, if applicable, the Fast Track Process has been completed. If the Interconnection Customer decides to not proceed with the feasibility study the Interconnection Application will be considered withdrawn.

D. The scope of and cost responsibilities for the feasibility study are described in the attached feasibility study agreement (ATTACHMENT 5). The feasibility study agreement shall specify that the Interconnection Customer is responsible for the actual cost of the feasibility study, and require the Interconnection Customer to include with the signed agreement certain technical data identified in (ATTACHMENT A) to the Feasibility Study Agreement (ATTACHMENT 5). The EPS Operator ~~may require a deposit~~ will be required to make an upfront full payment of the ~~lesser of (i) one thousand ($1,000) dollars or (ii) fifty percent (50%)~~ cost of the ~~good faith estimated feasibility~~ study ~~costs, from~~, a true up cost will be done at the ~~Interconnection Customer~~ end of the study.

E. If an Interconnection Customer requests that the feasibility study evaluate multiple potential Points of Common Coupling, any additional evaluations shall be paid for by the Interconnection Customer.

F. To remain in consideration for interconnection, an Interconnection Customer must return the executed feasibility study agreement and pay the required study deposit within five (5) Business Days.

G. The feasibility study shall consider a base case,[6] as well as all Generating Facilities and Microgrids (and any identified Network Upgrades) that, on the date the study commenced: (i) are directly interconnected to the EPS; (ii) have a pending higher or lower queued Interconnection Application depending in the geographical location of the project; and (iii) have no Queue Position but have executed an Interconnection Agreement. The feasibility study will consist of a power flow and short circuit analysis. The feasibility study shall consider the proposed interconnection's Export Capacity, design, and operating characteristics and study the project according to how it is proposed to be operated if the proposed interconnection complies with Section 1.47~~Section~~

Commented [A17]: The EPS operator could simultaneously study two or more valid Interconnection Requests within the Queue as a Cluster Study on the basis of geographic location and proposed electrical interconnection as specified in the Interconnection Requests in a nondiscriminatory manner.

[6] Base case means the power flow, short circuit, and stability data reflecting the current system conditions.

~~5.12~~1.47, uses devices tested to national standards, or is approved by the EPS Operator.

H. A feasibility study report shall be completed and transmitted to the Interconnection Customer within ~~twenty (20~~an average of forty (40) Business Days after the feasibility ~~impact~~ study agreement is signed by the Parties. The feasibility study report shall identify any potential adverse system impacts that would result from the interconnection as proposed, including but not limited to:

(1) Initial identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;

(2) Initial identification of any thermal overload or voltage limit violations resulting from the interconnection;

(3) Initial review of grounding requirements per IEEE C62.92.6 for inverter-based systems, and electric system protection; and

(4) Description and non-binding good faith estimated cost and construction schedule of facilities required to interconnect and to address the identified short circuit and power flow issues, including identification of potential increased expenses due to location, Distribution System assets, or other relevant factors. Good faith cost estimates provided in each instance should be itemized and break down costs by equipment, labor and other cost categories. They should also provide the components for direct, indirect, and other identified cost categories .

I. The EPS Operator may not require a system impact study when the feasibility study concludes there is no adverse system impact, or when the study identifies an adverse system impact, but the EPS Operator is able to identify a remedy without the need for a system impact study.

SECTION 1.34. System Impact Study.

A. A system impact study shall identify and detail the incremental EPS impacts that would result if the proposed Generating Facility or Microgrid interconnected without project modifications or EPS modifications, and study potential impacts, including but not limited to those identified in the scoping meeting. A system impact study shall evaluate the impact of the proposed interconnection on the reliability of the EPS. This may include evaluation of impacts to portions of the EPS within the boundaries of a Microgrid. A system impact study shall consider all Generating Facilities and Microgrids (and any identified Network Upgrades) that, on the date the study commenced: (i) are directly interconnected to the EPS; (ii) have a pending higher queued Interconnection Application; and (iii) have no Queue Position but have executed an Interconnection Agreement. The system impact study shall consider the proposed interconnection's Export Capacity, design, and operating characteristics and study the project according to how it is proposed to be operated if the proposed interconnection complies with Section 1.47~~Section 5.121.47~~, uses devices tested to national standards, or is approved by the EPS Operator.

B. The EPS Operator shall provide the Interconnection Customer a system impact study agreement (ATTACHMENT 6) according to the following timeline:

(1) In tandem with the results of the Interconnection Customer's feasibility study.

(2) If the feasibility study is omitted, as soon as possible, but not later than ~~three (3~~five (5) Business Days after the scoping meeting.

(3) If the scoping meeting and feasibility study are omitted , within an average of ten (10) Business Days after the Interconnection Application is deemed complete and, if applicable, the Fast Track Process has been completed.

C. The system impact study agreement (ATTACHMENT 6) shall include an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study. The scope of and cost responsibilities for a system impact study are described in the attached system impact study agreement. A deposit of the good faith estimated costs for each system impact study shall be provided by the Interconnection Customer when it returns the study agreements.

D. To remain in consideration for interconnection, an Interconnection Customer who has requested a system impact study must return the executed system impact study agreement and pay the required study deposit detailed in (ATTACHMENT 6) within five (5) Business Days.

E. A system impact study shall be completed and the results transmitted to the Interconnection Customer within ~~twenty-five (25~~an average of forty (40) Business Days after the system impact study agreement is signed by the Parties. The system impact study report shall provide:

(1) The underlying assumptions of the study.

(2) A summary of the analyses.

(3) The results of the analyses, including detailed information on any impacts identified, the drivers and reasons for those impacts, including load, voltage, thermal and other limitations as well as the boundaries of the impacts to the extent possible.

(4) Identification of any equipment short circuit capability limits exceeded as a result of the interconnection and information regarding technical thresholds that drive modifications.

(5) Identification of any protection elements being de-sensitized and reduction in performance grounding as a result of the interconnection and information regarding technical thresholds that drive modifications.

~~(5)~~(6) Identification of any thermal overload or voltage limit violations resulting from the interconnection and information regarding technical thresholds that drive modifications.

~~(6)~~(7) Identification of any instability or inadequately damped response to system disturbances resulting from the interconnection, and information regarding technical thresholds that drive modifications.

~~(7)~~(8) A non-binding construction schedule and good faith estimate of cost and time to construct any required distribution upgrades. Good faith cost estimates should be itemized and break down costs by equipment, labor and other cost categories. They should also provide the components for direct, indirect, and other identified cost categories.

F. Where the system impact study shows potential for Transmission System adverse system impacts, within an average of five (5) Business Days following the identification of such impacts, the EPS Operator shall send the Interconnection Customer a Transmission System impact study agreement, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study.

G. To remain in consideration for interconnection, an Interconnection Customer must return the executed Transmission System impact study agreement within fifteen (15) Business Days.

H. A Transmission System impact study, if required, shall be completed within an average of thirty (30) Business Days and the results transmitted to the Interconnection Customer after the Transmission System impact study agreement is signed by the Parties.

SECTION 1.35. Facilities Study

A. The EPS Operator shall provide the Interconnection Customer a facilities study agreement according to the following timeline:

(1) In tandem with the results of the system impact study or, if required, Transmission System impact study.

(2) If no system impact studies are required and feasibility study is performed, in tandem with the results of the feasibility study.

(3) If no studies are performed, as soon as possible, but not later than five (5) Business Days after the scoping meeting.

(4) If the scoping meeting is omitted by agreement and no studies are performed, within an average of ten (10) Business Days after the Interconnection Application is deemed complete and, if applicable, the Fast Track Process has been completed.

B. The facilities study agreement shall come with an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the facilities study. The scope of and cost responsibilities for the facilities study are described in the attached facilities study agreement. A deposit of the good faith estimated costs for the facilities study shall be provided by the Interconnection Customer when it returns the study agreement.

C. To remain under consideration for interconnection, the Interconnection Customer must return the executed facilities study agreement and pay the required study deposit within ten (10) Business Days.

D. The facilities study shall specify and estimate the cost of the equipment, permitting, engineering, procurement and construction work (including overheads) needed to implement the conclusions of the system impact study(s).

E. Design for any required Interconnection Facilities and/or Upgrades shall be performed under the facilities study agreement. The EPS Operator may contract with consultants to perform activities required under the facilities study agreement. The Interconnection Customer and the EPS Operator may agree to allow the Interconnection Customer to separately arrange for the design of some of the Interconnection Facilities. In such cases, facilities design will be reviewed and/or modified before acceptance by the EPS Operator, under the provisions of the facilities study agreement. If the Parties agree to separately arrange for design and construction, and provided security and confidentiality requirements can be met, the EPS Operator shall provide sufficient information to the Interconnection Customer in accordance with confidentiality and critical infrastructure requirements to permit the Interconnection Customer to obtain an independent design and cost estimate for any necessary facilities.

F. The facilities study must be completed and provided to Interconnection Customer within ~~twenty-five (25~~an average of sixty (60) Business Days of receiving the executed facilities study agreement. The facilities study shall estimate the cost of the equipment, engineering, procurement and construction work, including overheads, needed to implement the conclusions of the interconnection feasibility study and the interconnection system impact study. Good faith cost estimates shall be itemized and break down costs by equipment, labor and other cost categories. They should also provide the components for direct, indirect, and other identified cost categories. The facilities study shall consider the proposed interconnection's Export Capacity, design and operating characteristics and study the project according to how it is proposed to be operated if the proposed interconnection complies with Section 1.47~~Section 5.121.47~~, uses devices tested to national standards, or is approved by the EPS Operator. The facilities study shall identify:

(1) The electrical switching configuration of the equipment, including transformer, switchgear, meters and other station equipment.

(2) The nature and estimated cost of the EPS Operator's interconnection facilities and upgrades necessary to accomplish the interconnection.

(3) A good faith estimate for the time required to complete the construction and installation of the facilities.

G. Once the facilities study is completed, a draft facilities study report shall be prepared and transmitted to the Interconnection Customer. Upon request, the EPS Operator shall provide Interconnection Customer supporting documentation, workpapers, and databases or data developed to prepare the facilities study, subject to confidentiality arrangements consistent with these Regulations and the facilities study agreement.

H. Within an average of three (3) Business Days of providing a draft Facilities Study Report to the Interconnection Customer, the EPS Operator and Interconnection Customer shall ~~meet~~set up a mutually agreeable meeting date to discuss the results of the facilities study.

I. Interconnection Customer may, within eight (8) Business Days after receipt of the draft report, provide written comments to the EPS Operator, which the EPS Operator shall include in the final report.

J. The EPS Operator shall issue the final facilities study report and provide it to the Interconnection Customer within an average of nine (9) Business Days of receiving Interconnection Customer's comments or within an average of five (5) Business Days upon receiving Interconnection Customer's statement it will not provide comments.

PROVISIONS THAT APPLY TO ALL INTERCONNECTION APPLICATIONS

SECTION 1.36. Interconnection Agreement

A. Except as provided in Section 1.37~~Section 5.021.37~~, the EPS Operator shall provide the Interconnection Customer an executable Interconnection Agreement according to the following timeline:

(1) Within an average of five (5) Business Days after completing the final facilities study report.

(2) If no facilities study is required, within an average of five (5) Business Days after completing the system impact study or, if required, Transmission System impact study.

(3) If no facilities or system impact study is required, within an average of five (5) Business Days after completing the feasibility study.

(4) If no feasibility, facilities, or system impact study is required, ~~withinfive (5~~within an average of fifteen (15) Business Days after the scoping meeting.

Commented [A18]: There may be secondary changes – service conductor, metering, service transformer, etc. that doesn't require the other studies but will require some upgrade estimate and inclusion in the Interconnection Agreement.

(5) If no feasibility, facilities , or system impact study is required, and the scoping meeting is omitted by agreement, within an average of ten (10) Business Days after the Interconnection Application is deemed complete and, if applicable, the Fast Track Process has been completed.

B. After receiving an Interconnection Agreement from the EPS Operator, the Interconnection Customer shall have thirty (30) Business Days to sign and return the Interconnection Agreement.

C. The Interconnection Agreement must be signed by the Interconnection Customer and include a signed certification from a professional engineer that the interconnection meets the specifications established through regulations by the Energy Bureau and that the same was completed according to the laws, regulations, and rules applicable to interconnections.

D. If the Interconnection Customer does not sign the Interconnection Agreement or request an extension pursuant to these Regulations, within thirty (30) Business Days, the Interconnection Application shall be deemed withdrawn.

E. The EPS Operator shall provide the Interconnection Customer an executed Interconnection Agreement within ~~two (2~~an average of five (5) Business Days after receiving a signed Interconnection Agreement from the Interconnection Customer.

F. The EPS Operator shall install (if necessary) and configure any meters required for operation of the Generating Facility within an average of twenty (20) working days after the Interconnection Customer signs the executed Interconnection Agreement, provided that the Interconnection Application included such a request,

G. After the Interconnection Agreement is signed by the Parties, the interconnection of the Microgrid shall proceed under the provisions of the Interconnection Agreement, except to the extent these Regulations remain applicable, including, but not limited to, Section 1.39~~Section 5.04~~1.39, Section 1.41~~Section 5.06~~1.41, Section 1.42~~Section 5.07~~1.42, Section 1.46~~Section 5.11~~1.46 ~~and Article 6.~~ and Article 6.

SECTION 1.37. Energy Bureau's Approval for Microgrids Above 5 MW

For Microgrids with an Export Capacity above 5 MW, after the Facilities Study has been completed according to Section 1.35~~Section 4.05~~1.35, the Interconnection Customer or the EPS Operator shall submit the completed System Impact Study and Facility Study to the Energy Bureau for approval. If approved by the Energy Bureau, the EPS Operator shall issue the corresponding Interconnection Agreement in accordance with Section 1.36~~Section 5.01~~1.36, as applicable.

SECTION 1.38. Time Frames and Extensions

A. The EPS Operator shall make Reasonable Efforts to meet all time frames provided in these Regulations. If the EPS Operator cannot meet a deadline provided herein, it shall notify the Interconnection Customer and the Energy Bureau, explain the reason for the failure to meet the deadline, and provide an estimated time by which it will complete the applicable interconnection procedure in the process.

B. The Energy Bureau may fine the EPS Operator one thousand dollars ($1,000) per day if it fails to comply with the time frames and other requirements of this Regulation~~.~~ if it can be shown that the EPS Operator was negligent in fulfilling its duties. The Energy Bureau also maintains the authority to impose other applicable fines or administrative penalties to enforce its orders and regulations.

C. For all applicable time frames described in this Regulation, the Interconnection Customer ~~may request in writing one~~will be granted an automatic extension equivalent to half of the time originally allotted (*e.g.*, ten (10) Business Days for a twenty (20) Business Day original time frame). No further extensions shall be granted absent a Force Majeure Event or other similarly extraordinary circumstances.

Commented [A19]: LUMA understands the need for extensions and will grant this automatically to prevent the need to receive and process multiple extension requests that may result in an administrative burden if high volume of requests are received. In addition this would also add complexity in programming the DG portal.

~~SECTION 1.39. Interconnection Metering and Telemetry~~

Commented [A20]: This section will be eliminated in later revisions, as it will be referenced in the TIR. [See TIR, Section 10, Plant Revenue Metering]

~~For a Generating Facility with a~~ Nameplate ~~capacity of over 1 MW interconnected with the Transmission System, the Interconnection Customer is responsible for providing, installing, and maintaining two power meters at the Point of Common Coupling for exclusive use of the EPS Operator; one located at the exit of the generator for the measurement of its production, instantaneous power (active and reactive) and power factor; and the other meter for metering instantaneous power (active and reactive) of the Energy Storage system. All Metering needed shall be installed at the Interconnection Customer's expense in accordance with local regulatory requirements or the EPS Operator's specifications. The EPS Operator provides the specification of these meters and equipment to use for communication with the SCADA system. The meters will energize through a current transformer (CT) and potential transformer (PT) with metering measurement class. The meter of the Energy Storage system must provide as a minimum the following digital signals:~~:

~~1) Active power in the storage system (kW)~~

~~2) State of charge (SOC)~~

~~3) System availability: enabled or disabled~~

~~4) Energy equivalent available for the requirement of frequency response~~

~~5) Average solar radiation (inclined plane)~~

~~If necessary, any other signal that cannot be obtained by means of meters, the Interconnection Customer will be required to establish an additional communication from the plant controller (PPC) of the Generating Facility towards the required communication equipment.~~

SECTION 1.40. Non-Warranty

Neither by inspection, if any, or non-rejection, nor in any other way, does the EPS Operator give any warranty, expressed or implied, as to the adequacy, safety, or other characteristics of any structures, equipment, wires, appliances or devices owned, installed, or maintained by the Interconnection Customer or leased by the Interconnection Customer from third parties, including without limitation the Generation System and any structures, equipment, wires, appliances, or devices pertinent thereto.

SECTION 1.41. Commissioning, Inspection, Testing, Authorization

A. The Interconnection Customer shall test and inspect its Generating Facility, Microgrid, and Interconnection Facilities before interconnection in accordance with the commissioning tests required by ~~IEEE 1547.~~ the Technical Interconnection Requirements (TIR) document Commissioning tests of the Interconnection Customer's installed equipment shall be performed pursuant to applicable codes and standards and the EPS Operator's ~~interconnection handbook.~~ Technical Interconnection Requirements document.

B. The Interconnection Customer shall notify the EPS Operator[7] of such activities at least ten (10) Business Days (or as agreed to by the Parties) before such testing and inspection. The Interconnection Customer shall send the notification electronically if the Cyber Portal is available. If the Cyber Portal is not available, the Interconnection Customer shall use a notification form provided by the EPS Operator, if such a form is posted on the EPS Operator's website. Testing and inspection shall occur on a Business Day. The EPS Operator may, at its own expense, send qualified personnel to the interconnection site to inspect the interconnection and observe the testing. The Interconnection Customer shall provide the EPS Operator a written test report within five (5) Business Days when such testing and inspection is completed.

C. The EPS Operator shall provide the Interconnection Customer written acknowledgment it has received the Interconnection Customer's written test report within an average of three (3) Business Days of its receipt. If no written acknowledgement is received by the Interconnection Customer within three (3) Business Days it shall be deemed accepted by the EPS Operator. Such written acknowledgment shall not be deemed to be or construed as any representation, assurance, guarantee, or warranty by the EPS Operator of the safety, durability, suitability, or reliability of the interconnection.

D. For interconnections using the Simplified Process, the field inspection and testing process shall conform with, and not exceed, the following:

(1) The field inspection shall include verification that the installation matches the EPS Operator's evaluation of the design, including:

(2) Inverter model matches application;

(3) Certified inverter(s) is utilized;

(4) Correct labeling/signage;

(5) Installation matches application one-line (*i.e.*, connections, location of protection, disconnect switch, Metering, etc.);

(6) Electrical inspection sticker;

(7) Operational and protection settings;

[7] If PREPA is the EPS Operator, the Interconnection Customer shall notify the PREPA Office of Inspections in the appropriate region.

(8) Field testing; and

(9) On-off testing shall be completed.

SECTION 1.42. Authorization Required Prior to Parallel Operation

A. The EPS Operator shall use Reasonable Efforts to list applicable Parallel Operation requirements in an attachment to the Interconnection Agreement. Additionally, the EPS Operator shall notify the Interconnection Customer of any changes to these requirements as soon as they are known. The EPS Operator shall make Reasonable Efforts to cooperate with the Interconnection Customer in meeting requirements for the Interconnection Customer to commence Parallel Operations by the in-service date.

B. The Interconnection Customer shall not operate its Generating Facility or Microgrid in Parallel with the EPS without prior written authorization of the EPS Operator. The EPS Operator will provide such authorization within three (3) Business Days from when the EPS Operator receives notification that the Interconnection Customer has complied with all applicable Parallel Operation requirements. Such authorization shall not be unreasonably withheld, conditioned, or delayed.

C. If the EPS Operator identifies a Generating Facility Operating in Parallel without an Interconnection Agreement, the EPS Operator may disconnect the Generating Facility.

SECTION 1.43. Confidentiality

A. Each Party shall employ at least the same standard of care to protect Confidential Information obtained from the other Party as it employs to protect its own Confidential Information.

B. Each Party may have equitable relief, by injunction or otherwise, to enforce its rights under this provision to prevent the release of Confidential Information without bond or proof of damages and may seek other remedies available at law or in equity for breach of this provision.

SECTION 1.44. Insurance

A. The EPS Operator may only require an Interconnection Customer to purchase General Public Liability Insurance covering damages to the EPS Operator or PREPA, and then only in the following amounts:

B. Up to one million dollars ($1,000,000) per occurrence and up to one million dollars ($1,000,000) in the aggregate if the Generating Facility or Microgrid's Export Capacity is greater than 300 kW;

C. ~~No insurance is required if the Generating Facility or Microgrid's Export Capacity is less than or equal to 300 kW.~~The client receiving authorization from the EPS Operator to interconnect an inverter-based GD, with a capacity of less than 300 kW, with the transmission and sub transmission system is exempt from an insurance policy for General Public Liability. In these cases, the client must sign an Insurance Requirement Waiver Agreement (see Attachment XX). The client has the option to electronically sign this agreement through the EPS Operator cyber portal.

D. The general public responsibility policy will be endorsed as follows:

1. As an additional insured:

LUMA ENERGY SERVCO, LLC and
Puerto Rico Electric Power Authority
[Address TBD]

2. An endorsement that includes the Agreement under the cover of contractual liability by identifying the parties to the Agreement.

3. Release from subrogation statement in favor of the Authority and LUMA ENERGY SERVCO, LLC.

4. Notification of cancellation or non-renewal thirty (30) days in advance and with return receipt to the foregoing address.

5. Violation of any warranty or condition of this policy shall not prejudice the right of the Puerto Rico Electric Energy Authority and LUMA ENERGY SERVCO, LLC under such a directive.

E. The insurance policy has to be submitted in an acceptable manner to the EPS Operator. The client must provide an insurance certificate in digital format, originating with a company or insurance agency producer authorized to do business in Puerto Rico, describing the coverage it provides. This certification has to be issued on the *Acord* form, usually used for insurers. In addition, you have to include the endorsements in digital format.

F. The EPS Operator shall, within fifteen working days, assess the policy submitted and determine its acceptance. In the event that the policy does not meet the requirements of the EPS Operator, the EPS Operator shall notify the proponent, within the same amount of days, to make the corresponding corrections and present the policy before the EPS Operator again. Once the client submits the corrected information, the Authority will have a term of five working days to approve such insurance. In the event that the Authority does not notify the client of the approval or corrections corresponding to the insurance within the terms previously indicated, it will be understood that it is approved, and it is presumed that the client meets all the requirements.

G. This policy has to be renewed annually and sent to the EPS Operator. In the event that this policy renewal requirement is not met, the EPS Operator shall immediately terminate the Agreement.

SECTION 1.45. Comparability

The EPS Operator shall receive, process and analyze all Interconnection Applications as set forth in this Regulation. The EPS Operator shall use the same Reasonable Efforts in processing and analyzing Interconnection Applications from all Interconnection Customers, whether the proposed interconnection is owned or operated by the EPS Operator, PREPA, their subsidiaries or affiliates, or others.

SECTION 1.46. Design, Procurement, Installation and Construction of Interconnection Facilities and Upgrades

A. The Interconnection Customer shall pay for the cost of the Interconnection Facilities and Distribution Upgrades as described and itemized pursuant to the Interconnection Agreement and its attachments.

B. If Network Upgrades are required, the actual cost of the Network Upgrades, including overheads, shall be borne initially by the Interconnection Customer; provided, however, that the Interconnection Customer may have a cash repayment pursuant to the Interconnection Agreement. As stated in the Interconnection Agreement, the EPS Operator shall provide a best estimate cost, including overheads, for the purchase and construction of the Interconnection Facilities, Distribution Upgrades, and Network Upgrades, and provide a detailed itemization of such costs (i.e. the estimates shall break out the materials, labor and other costs for major components of the Upgrades).

C. The Interconnection Customer and the EPS Operator shall agree on milestones for which each Party is responsible and list them in an attachment to the Interconnection Agreement. To the greatest extent possible, the Parties will identify all design, procurement, installation and construction requirements associated with a project, and clear associated timelines, at the beginning of the design, procurement, installation and construction phase, or as early within the process as possible. All timelines shall comport with industry best practices. In addition, whenever possible to capture additional efficiency, the EPS Operator will rely on template designs applicable to certain types of interconnections. These templates shall be publicly available on the EPS Operator's web site and/or provided directly to any interested entity upon request.

D. Party's obligations under this provision may be extended by agreement. If a Party anticipates that it will be unable to meet a milestone for any reason other than a Force Majeure Event, it shall immediately notify the other Party of the reason(s) for not meeting the milestone and (1) propose the earliest reasonable alternate date by which it can attain this and future milestones, and (2) request appropriate amendments to the Interconnection Agreement and its attachments. The Party affected by the failure to meet a milestone shall not unreasonably withhold agreement to such an amendment unless (1) it will suffer significant uncompensated economic or operational harm from the delay, (2) attainment of the same milestone has previously been delayed, or (3) it has reason to believe that the delay in meeting the milestone is intentional or unwarranted notwithstanding the circumstances explained by the Party proposing the amendment. If the Party affected by the failure to meet a milestone disputes the proposed extension, the affected Party may pursue dispute resolution pursuant to Article 8 of this Regulation.

E. At least twenty (20) Business Days before the commencement of the design, procurement, installation, or construction of a discrete portion of the EPS Operator's Interconnection Facilities and Upgrades, the Interconnection Customer shall provide the EPS Operator, at the Interconnection Customer's option, a guarantee, a surety bond, letter of credit or other form of security reasonably acceptable to the EPS Operator and is consistent with the Puerto Rico Uniform Commercial Code. Such security for payment shall be in an amount sufficient to cover the costs for constructing, designing, procuring, and installing the portion of the EPS Operator's Interconnection Facilities and Upgrades and shall be reduced on a dollar-for-dollar basis for payments made to the EPS Operator under the Interconnection Agreement during its term. In addition:

(1) The guarantee must be made by an entity that meets the creditworthiness requirements of the EPS Operator and contain terms and conditions that guarantee payment of any amount that may be due from the Interconnection Customer, up to an agreed-to maximum amount.

(2) The letter of credit or surety bond must be issued by a financial institution or insurer reasonably acceptable to the EPS Operator and must specify a reasonable expiration date.

F. The EPS Operator shall bill the Interconnection Customer for the design, engineering, construction, and procurement costs of Interconnection Facilities and Upgrades described in the Interconnection Agreement monthly, or as otherwise agreed by the Parties in the Interconnection Agreement. The Interconnection Customer shall pay each bill within twenty (20) Business Days of receipt, or as otherwise agreed to by the Parties in the Interconnection Agreement.

G. Within three (3) months of completing the construction and installation of the EPS Operator's Interconnection Facilities and/or Upgrades described in the Interconnection Agreement and its attachments, the EPS Operator shall provide the Interconnection Customer with a final accounting report of any difference between (1) the Interconnection Customer's cost responsibility for the actual cost of such facilities or Upgrades, and (2) the Interconnection Customer's previous aggregate payments to the EPS Operator for such facilities or Upgrades. If the Interconnection Customer's cost responsibility exceeds its previous aggregate payments, the EPS Operator shall invoice the Interconnection Customer for the amount due and the Interconnection Customer shall pay to the EPS Operator within twenty (20) Business Days. If the Interconnection Customer's previous aggregate payments exceed its cost responsibility under the Interconnection Agreement, the EPS Operator shall refund to the Interconnection Customer an amount equal to the difference within twenty (20) Business Days of the final accounting report.

SECTION 1.47. Export Capacity of a Generating Facility or Microgrid

A. The technical specifications in this Section 1.47~~Section 5.12~~1.47 are intended to identify acceptable Export Control methods to facilitate the interconnection and Parallel Operation of Limited-Export and Non-Export Generating Facilities and Microgrids with the EPS.

If a Generating Facility or Microgrid uses any configuration or operating mode in this Section 1.47~~Section 5.12~~1.47, to limit the export of electrical power across the Point of Common Coupling, then the Export Capacity shall be only the amount capable of being exported (not including any Inadvertent Export). To prevent impacts on system safety and reliability, any Inadvertent Export must comply with the limits identified in this section. The Export Capacity specified in the Interconnection Application will be included as a limitation in the Interconnection Agreement. An Interconnection Customer seeking to interconnect using the operating modes under this Section 1.47~~Section 5.12~~1.47 shall submit proposed control and/or protection settings in their Interconnection Application for review by the EPS Operator to verify compliance with the requirements of this Section.

For all types of Generating Facilities or Microgrids, the System Impact Study will determine if more stringent requirements are necessary. Those requirements will reference the TIR document and will be specified and stipulated in the Interconnection Agreement.

B. The export controls identified in this subsection are for Non-Exporting systems only.

(1) Reverse Power Protection: To limit export of power across the Point of Common Coupling, a reverse power protective function is implemented using a utility grade protective relay. The default setting for this protective function shall be 0.1% (export) of the Interconnection

Transformer's nominal base Nameplate Rating, with a maximum 2.0 second time delay to limit Inadvertent Export.

(2) Minimum Power Protection: To limit export of power across the Point of Common Coupling, a minimum import protective function is implemented utilizing a utility grade protective relay. The default setting for this protective function shall be 5% (import) of the generating unit's total Nameplate Rating, with a maximum 2.0 second time delay to limit Inadvertent Export.

(3) Relative Generating Facility Rating: This option requires the Generating Facility or Microgrid's Nameplate Rating to be so small compared to the minimum Host Load that using additional protective functions does not have to ensure that power will not be exported to the EPS. This option requires the Generating Facility or Microgrid's Nameplate Rating be no greater than 50% of the verifiable minimum Host Load over the past 12 months.

For Generating Facilities or Microgrids with a Nameplate Rating above 250 kW, the EPS Operator may require additional assurances, equipment or agreements based upon evaluation of the stability and reliability of the minimum Host Load data.

C. The export controls identified in in this subsections are for Limited Export systems only.

(1) Directional Power Protection: To limit export of power across the Point of Common Coupling, a directional power protective function is implemented using a utility grade protective relay. The default setting for this protective function shall be the Export Capacity value, with a maximum 2.0 second time delay to limit Inadvertent Export.

(2) Configured Power Rating: A reduced output active or apparent power rating utilizing the power rating configuration setting may be used to ensure the Generating Facility or Microgrid does not generate power beyond a certain value lower than the Nameplate Rating. The reduced power rating shall be indicated with a Nameplate Rating replacement, or by a supplemental adhesive Nameplate Rating tag to indicate the reduced Nameplate Rating. At the discretion of the EPS Operator, the applicant may additionally be required to provide a letter from the manufacturer confirming the reduced Nameplate Rating.

D. The export controls identified in this subsection are for either Non-Export or Limited Export systems.

(1) Power Control Systems: This option is not available for interconnections to Networked Secondary Systems. A Generating

Facility or Microgrid may utilize a NRTL certified Power Control System[8] and inverter system with a maximum open loop response time of no more than 30 seconds. Failure of the control or inverter system resulting from abnormal conditions must result in the Generating Facility or Microgrid entering an operational mode where no energy is exported across the Point of Common Coupling to the EPS.

If a Generating Facility or Microgrid with a Nameplate Rating greater than 1 MW uses an NRTL certified Power Control System, the EPS Operator and the Interconnection Customer must mutually agree on an acceptable open loop response time.

(2) Limited Export Using Mutually Agreed-Upon Means: Generating Facilities or Microgrids may be designed with other control systems and/or protective functions to limit export and Inadvertent Export by agreement between the EPS Operator and the Interconnection Customers. The limits may be based on technical limitations of the Interconnection Customer's equipment or EPS equipment. To ensure Inadvertent Export remains within mutually agreed-upon limits, the Interconnection Customer may use an uncertified Power Control System, an internal transfer relay, energy management system, or other customer facility hardware or software if approved by the EPS Operator.

E. If the Interconnection Application proposes to limit export pursuant to this Section 1.47~~Section 5.121.47~~, the Fast Track screens, and feasibility, system impact, and transmission studies shall study the project according to how it intends to operate. When performing these studies, the EPS Operator:

(1) Shall consider the proposed design, operating characteristics, Export Capacity, and Operating Profile found in the Interconnection Application.

(2) Shall use the Export Capacity unless assessing fault current contribution, when the use of the Nameplate Rating may be appropriate. The EPS Operator may use Export Capacity when assessing fault current contribution if the Interconnection Customer demonstrates that fault currents are controlled by some means. The Fast Track screens identify when it is appropriate to use Export Capacity or Nameplate Rating.

[8] NRTL testing to the UL Power Control System Certification Requirements Decision shall be accepted until similar test procedures for Power Control Systems are included in a standard.

TECHNICAL REQUIREMENTS

SECTION 1.48. General Technical Requirements

The EPS Operator will develop Technical Interconnection Requirements consistent with the requirements of this Regulation which shall be submitted to the Energy Bureau for the Energy Bureau's review and approval within thirty (30) Business Days from approval of this Regulation (the "TIR"). The TIR may be amended by the EPS Operator from time to time provided these changes are consistent with the requirements of this Regulation and the EPS Operator submits such amendments for the Energy Bureau's prior review and approval.

A. The technical requirements ~~in the following sections~~ apply to Generating Facilities and Microgrids when designed to operate in Parallel, and shall be met at the Point of Common Coupling.

B. The technical requirements ~~in this Article~~ are established in accordance with standards from IEEE, UL and ANSI, as applicable for the interconnection of Generating Facilities and Microgrids to the EPS. Compliance with these requirements is intended to prevent the Generating Facility or Microgrid from causing adverse effects to the EPS such that it may have to be disconnected due to unsafe operating conditions.

C. The Technical Interconnection Requirements (TIR) document shall provide guidance for grid interconnection and parallel operation with the grid. It shall provide criteria for EPS Operator engineers, as well as customers and developers planning to interconnect distributed energy resources (DERs) with the utility distribution system. Both Transmission and Distribution medium voltage and low voltage connections shall be covered in the TIR. The requirements in the TIR shall apply to all aspects of DER connection and operation with the utility grid.

The TIR document shall address responsibilities of the Interconnecting Customer (IC) related to the grid integration, point of connection, and general system performance. It shall include operational performance, power quality, protection, monitoring, control, and telemetry requirements. Interoperability with other grid equipment as well as metering, commissioning test and verification requirements shall be addressed. The document shall also cover specific operating requirements and any special protection that may be required for connections on radial or network locations in the distribution grid.

~~C.~~D. This regulation incorporates IEEE Std 1547-~~2003 (inclusive of IEEE Std 1547a-2014).~~2018. Where conflicts exist between IEEE Std 1547-2018 and this regulation, the TIR document or this regulation ~~shall take~~takes precedence~~.~~

~~D.~~E. A Generating Facility interconnecting to the Distribution System must interconnect through an Interconnection Transformer. A direct

Commented [A21]: [NOTE TO THE REVIWER]: Sections 1.50 to 1.58 will be moved and addressed in the Technical Interconnection Requirement document (TIR). The TIR should not be part of this regulation. Rather, it should be a separate document to be approved by the Energy Bureau in a non-rulemaking proceeding that may be amended from time to time without having to go through rule-making each time. This note, as well as the rest of the aforementioned sections will be relocated in the TIR. We have added reference to illustrate where each topic is addressed in the TIR.

interconnection to the Distribution System without a transformer is not permitted.

~~E.~~F. For Microgrids, the technical requirements of Section 1.50~~Section 6.03~~1.50, Section 1.52~~Section 6.05~~1.52 and Section 1.53~~Section 6.06~~1.53 may be satisfied by the individual Generating Facilities within the Microgrid, by other Microgrid equipment, or by coordination between Generating Facilities and other Microgrid equipment.

~~F.~~G. For further information regarding these interconnection requirements, see the ~~EPS Operator's interconnection handbook~~Technical Interconnection Requirements document.

SECTION 1.49. Approval of Use of Certified Equipment

A. All equipment that forms part of a Generating Facility system based on renewable energy sources must be approved by the Public Energy Policy Program ("PEPP"), of the Department of Economic Development and Commerce ("DEDC") including, but not limited to, photovoltaic modules, wind turbines, synchronous generators, induction generators, inverters and control systems. PEPP must certify that the inverters and control systems that interconnect the renewable energy sources with the electrical network comply with the ~~IEEE 1547, UL 1741, and other~~ applicable standards. The list of equipment and components certified by the PEPP is available on the Energy Bureau's website (http://energia.pr.gov).

B. The EPS Operator allows the use of equipment with inverter technology, generators, relays and other devices that comply with applicable standards and codes. These have to be evaluated and approved by the EPS Operator.

C. The EPS Operator has a list of approved inverters and control systems periodically updated~~. If a proposed inverter or control system is not included in the list, the Interconnection Customer must send the manufacturer's manual, in PDF digital file, to the EPS Operator for its evaluation. This process is besides the certification issued by the "Oficina de Gerencia de Permisos" (OGPe) after approval by the PEPP.~~, which is made available on the DG Portal website.

D. If the equipment has not been evaluated and approved by the EPS Operator, it may request that the manufacturer, distributor or owner send to the EPS Operator, in digital file in PDF format, documents certifying that the inverter complies with the following:

(1) Are certified by a Nationally Recognized Testing Laboratory. This ensures that they meet the acceptance criteria of the tests required in the IEEE 1547-2018

or UL 1741 standard and its Supplements, as applicable, for equipment that operates continuously in parallel with the systems of the electricity companies.

(2) Comply with the permitted harmonic content distortion limits, according to the IEEE ~~519~~1547-2018 standard and other applicable ones.

(3) Comply with the Voltage Flicker limits, depending on the IEEE ~~1453~~1547-2018 standard and other applicable.

(4) Comply with these regulations. Should any conflict arise with other standards, these regulations will prevail.

(5) Have the ability to Operate in Parallel with the EPS.

(6) Have the ability to adjust in the field of frequency, voltage and operating times.

E. For further information regarding these interconnection requirements, see the Technical Interconnection Requirements document.

SECTION 1.50. ~~Unintentional Island Detection~~

~~The Generating Facility or Microgrid must be equipped with the devices and protection programming designed to prevent energization of a de-energized EPS circuit. If a situation arises that an electrical Island activates, the Generating Facility or Microgrid must Cease to Energize the EPS and Trip in less than two seconds response time.~~

SECTION 1.51. Intentional Islanding for Microgrids

~~A. A Microgrid may disconnect[9] from the EPS and Intentionally Island in accordance with the following:~~

~~(1) As an alternative to Trip in response to Unintentional Island detection as required by Section 1.50Section 6.031.50.~~

~~(2) As an alternative to Trip in response to voltage disturbances as required by Section 1.52.BSection 6.051.52.B.~~

~~(3) As an alternative to Trip in response to frequency disturbances as required by Section 1.52.CSection 6.051.52.C.~~

~~(4) When issued a planned Island request by the EPS Operator, and shall meet the criteria of either Section 1.51Section 6.041.51 B(1) or B(2).~~

~~(5) When Paralleling a Microgrid to the EPS, the Enter Service and synchronization requirements of Section 1.53Section 6.061.53 shall be met.~~

[9] Disconnection implies isolation.

Commented [A22]: [See TIR Sec 7 Protection Coordination Requirements, Art 7.2 Unintended Island Detection]

Commented [A23]: [See TIR Sec 7 Protection Coordination Requirements, Art 7.2 Unintended Island Detection and Section 13 Microgrids (TBD)]

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~~B. A Microgrid may Cease to Energize the EPS and Trip without limitations if any of the following applies:~~

~~(1) The net active power exported across the Point of Common Coupling into the EPS is continuously maintained at a value less than 10% of the aggregate Nameplate Rating of Generating Facilities connected to the Microgrid, and the Microgrid disconnects from the EPS, along with Microgrid load to form an Intentional Island, or~~

~~(2) An active power demand of the Microgrid load equal or greater than 90% of the pre-disturbance aggregate Generating Facility active power output is shed within 0.1 seconds of when the Generating Facility Ceases to Energize the EPS and Trips.~~

~~(3) If the Microgrid does not meet the criteria of Section 6.04 B(1) or B(2) the transition to the Microgrid shall meet the rapid voltage change requirements of Section 6.07.~~

~~C. Microgrid systems designated by the authority having jurisdiction~~EPS Operator ~~as emergency, legally required, or critical operations power systems providing backup power to hospitals, fire stations or other emergency facilities as defined by industry code, shall be exempt from the Intentional Islanding requirements specified in this section and may Cease to Energize the EPS and Trip without limitations.~~

~~SECTION 1.52. Voltage and Frequency Disturbances~~

Commented [A24]: [See TIR Section 6 DER Response to Abnormal Conditions. Arts. 6.4 & 6.5 Voltage/Frequency Trip and RT Requirements]

~~A. The system of protection and control of the Generating Facility or Microgrid must detect electrical disturbances that occur on the EPS. The Generating Facility or Microgrid shall Cease to Energize the EPS and Trip when the electrical disturbance occurs. The Generating Facility or Microgrid shall Cease to Energize before the first recloser operation of the circuit.[10] Once Tripped~~ Disconnected~~, the Generating Facility or Microgrid shall measure the voltage and frequency of the EPS at the Point of Common Coupling.[11] The Generating Facility or Microgrid shall Return to Service once the voltage and frequency remain at adequate levels as described in~~ ~~Section~~ 1.53~~Section 6.06~~1.53 ~~for at least fifteen (15) seconds. Generating Facility or Microgrid programming shall be adjusted so the Generating Facility or Microgrid Ceases to Energize and Trips according to the following requirements:~~

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[10] Ceasing to Energize without Tripping (known as "momentary cessation") meets the requirement of reclosing coordination.

[11] For Microgrids, this may be accomplished at the individual Generating Facility(ies) as long as the appropriate voltage and frequency is monitored and zero-sequence continuity is maintained between the EPS and Generating Facility measurement point.

B. ~~In the face of variations in voltage magnitude from electric service at the Point of Common Coupling, the Generating Facility or Microgrid shall Cease to Energize the EPS and Trip by the clearing time, as established in~~ ~~Table 2~~Table 2~~.~~

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C. ~~In the face of variations in frequency, the Generating Facility or Microgrid shall Cease to Energize the EPS and Trip by the clearing time, as established in~~ Table 3~~Table 3~~. ~~The protection and control system programming must include, at a minimum, four independent functions (two (2) for underfrequency and two (2) for over frequency) to enable it to fulfill the frequency ranges and time outs, as detailed on the table.~~

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~~Table 2: Trips for Voltage Variations~~

~~Voltage Range (% of Nominal Voltage)~~	~~Clearing Time (seconds)~~	~~Adjustable Clearing Time Range Up to and including (seconds):~~
~~V<45~~	~~0.16~~	~~0.16~~
~~45≤ V< 60~~	~~1~~	~~11~~
~~60≤ V< 88~~	~~2~~	~~21~~
~~110 <V< 120~~	~~1~~	~~13~~
~~V≥ 120~~	~~0.16~~	~~0.16~~
~~**Note:** These settings have to be programmed into the inverter or the protective equipment before the Generating Facility or Microgrid testing process. The EPS Operator may require other Trip times or frequency ranges, as established in the IEEE 1547.~~		

~~Table 3: Trips due to Frequency Variations~~

~~Function~~	~~Frequency (Hz)~~	~~Clearing Time (seconds)~~
~~Under-frequency 1~~	~~f < 57.5~~	~~10~~
~~Under-frequency 2~~	~~57.5 ≤ f < 59.2~~	~~300~~
~~Over-frequency 1~~	~~60.5 < f ≤ 61.5~~	~~300~~
~~Over-frequency 2~~	~~f > 61.5~~	~~10~~
~~**Note:** These settings have to be programmed into the inverter or the protective equipment before the Generating Facility or Microgrid testing process. The EPS Operator may require other Trip times or frequency ranges, as established in the IEEE 1547.~~		

~~SECTION 1.53. Enter Service and Synchronization~~

~~When Entering Service, the Generating Facility or Microgrid shall not energize the EPS until voltage and system frequency are within the ranges specified in **Table 4** below.~~

~~Table 4: Enter Service voltage and frequency criteria~~

~~Enter Service Criteria~~		~~Default Settings~~
~~Voltage within range~~	~~Minimum value~~	~~≥ 0.917 p.u.~~
	~~Maximum value~~	~~≤ 1.05 p.u.~~
~~Frequency within range~~	~~Minimum value~~	~~≥ 59.5 Hz~~
	~~Maximum value~~	~~≤ 60.1 Hz~~

~~The Generating Facility or Microgrid shall Parallel with the EPS without causing step changes in the root mean square (RMS) voltage at the Point of Common Coupling exceeding three percent (3%) of nominal when the Point of Common Coupling is at high or medium voltage, or exceeding five percent (5%) of nominal when the Point of Common Coupling is at low voltage.~~

~~Generating Facilities or Microgrids that produce fundamental voltage before connecting to the EPS shall not be synchronized outside of the tolerances specified in~~ **Table 5Table 5** ~~below. The synchronization limits stated in~~ **Table 5Table 5** ~~below may be waived by the EPS Operator if Paralleling does not exceed the rapid voltage change requirements of~~ Section 1.54Section 6.071.54 ~~nor applicable flicker requirements.~~

~~Table 5: Synchronization parameter limits for interconnection to the EPS~~

~~Aggregate rating of DER units (kVA)~~	~~Frequency difference (Δf, Hz)~~	~~Voltage difference (ΔV, %)~~	~~Phase angle difference (ΔΦ, °)~~
~~0–500~~	~~0.3~~	~~10~~	~~20~~
~~> 500–1500~~	~~0.2~~	~~5~~	~~15~~
~~> 1500~~	~~0.1~~	~~3~~	~~10~~

Commented [A25]: [See TIR Section 5 General Technical Requirements, Arts. 5.10 5.10.1 Enter Service & Synchronization]

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SECTION 1.54. Limitation of rapid voltage changes

Commented [A26]: [See TIR Section 9 Power Quality, Art 9.2 Limits on DER-caused Voltage Fluctuations]

A. When the Point of Common Coupling is at high or medium voltage, the Generating Facility or Microgrid shall not cause step or ramp changes in the RMS voltage at the Point of Common Coupling exceeding three percent (3%) of nominal and exceeding three percent (3%) per second averaged over a period of one second. When the Point of Common Coupling is at low voltage, the Generating Facility or Microgrid shall not cause step or ramp changes in the RMS voltage exceeding five percent (5%) of nominal and exceeding five percent (5%) per second averaged over a period of one (1) second. Any exception to the limits is subject to approval by the EPS Operator with consideration of other sources of rapid voltage changes within the EPS.

B. These rapid voltage change limits shall apply to sudden changes due to frequent energization of transformers, frequent switching of capacitors or from abrupt output variations caused by Generating Facility or Microgrid maloperation. These rapid voltage change limits shall not apply to infrequent events such as switching, unplanned Tripping, or transformer energization related to commissioning, fault restoration, or maintenance.

SECTION 1.55. Power Factor

Commented [A27]: [See TIR Article 5 DER Support of Grid Voltage]

The Generating Facility or Microgrid must be set to maintain a continuous unity power factor (PF = 1.0) at the Point of Common Coupling, in accordance with the following:

A. Generating Facilities or Microgrids interconnected to the Distribution System must operatebe capable of operating within the range of 0.9890 absorbing to 0.9890 injecting for all real power output greater than or equal to 25% of rated capacity (kW rated)..

B. Generating Facilities or Microgrids with lesser than 500 kW capacity interconnected to the Transmission System must operatebe capable of operating within the range of 0.98 90 absorbing to 0.9890 injecting for all real power output greater than or equal to 25% of rated capacity (kW rated)..

C. Generating Facilities or Microgrids with 500 kW to 1 MW capacity interconnected to the Transmission System must operatebe capable of operating within the range of 0.9890 absorbing to 0.9890 injecting for all real power output between 25% and 75% of rated capacity (kW rated). For real power output above 75% of rated capacity, it must operate within the range of 0.99 absorbing to 0.99 injecting.

D. Generating Facilities or Microgrids with greater than 1 MW Nameplate Rating interconnected to the Transmission System must operatebe capable of operating within the range of 0.99990 absorbing to 0.99990 injecting for all real power output greater than or equal to 25% of rated capacity (kW rated).

~~The flow of reactive power at the Point of Common Coupling, either absorbing or injecting, should not exceed 4.5% of its nominal capacity (kW rated)..~~

~~SECTION 1.56. Power Quality~~

Commented [A28]: [See TIR Section 9 Power Quality]

~~Generating Facilities or Microgrids shall comply with the following power quality requirements:~~

~~A. The Generating Facility or Microgrid shall meet the quality requirements of the electrical signal specified in the IEEE 519, IEEE 1453, IEEE 1159, IEEE 1547-20032018, UL 1741 and other applicable standardsits supplements and their revisions or successors.~~

~~B. The interconnection of the Generating Facility or Microgrid may not cause degradation in the quality of the signal of the EPS. Some examples of degradation in the quality of the electrical signal include, but are not limited to: imbalance and regulation, harmonic distortion, flicker, low voltage (sags), ferro-resonance interruptions, and transient phenomena. If these events arise, the Generating Facility or Microgrid has to be disconnected from the EPS until the Interconnection Customer makes the modifications to mitigate the problems with the quality of the electrical signal caused by Generating Facility or Microgrid. In those facilities without a manual switch as described in Section 1.58Section 6.111.58 or that do not provide access to EPS Operator to operate the switch, the disconnection will be from the disconnect device located at the Interconnection Customer's substation , which would interrupt electric service provided by the EPS to the Interconnection Customer.~~

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~~C. If the Generating Facility or Microgrid uses the EPS for start-up, it cannot cause voltage drops in the primary side of the interconnection of over 3%.~~

~~D. The EPS Operator may specify the configuration of the connection of the windings on the primary and secondary side of the 3-phase Interconnection Transformer of the Generating Facility or Microgrid, to assure that it does not degrade the quality of service.~~

~~E. Generating Facilities or Microgrids are interconnected to the Transmission System through an Interconnection Transformer, which can be the transformer that provides electric service to the customer loads. For interconnection to the Transmission System, the configuration of the interconnection of the windings on the primary (EPS) side is delta and in the secondary (customer) is star to Earth. The connection of this transformer has to be the type who produces in the primary side a voltage this advance 30° with respect to the secondary side voltage.~~

~~F. The Interconnection Customer is responsible to make and for the costs of the modifications to mitigate the problems with the quality of the electrical signal~~

~~that cause their Generating Facility or Microgrid to the EPS or other customers and to comply with the requirements set out in the standards outlined above.~~

~~G. If the Generating Facility or Microgrid includes induction generators, the Interconnection Customer is responsible for providing the reactive power compensation at start up to control any abrupt changes in voltage. The strategy to compensate for reactive power must be implemented through technologies that guarantee the absence of discontinuity, that is, maintain a continuous control of reactive power.~~

~~H. The Interconnection Customer is responsible for the injections of voltage and current with harmonic content and do not increase the thermal warming in the transformers and reactors, nor can cause failure, overloads or malfunction of equipment and resonant voltages, among others, to the EPS. They can interfere with the circuits and telecommunication systems or from signals.~~

~~SECTION 1.57. Frequency Droop~~

~~Generating Facilities with a Nameplate Rating greater than 1 MW interconnected to the Transmission System shall comply with the following:~~

~~A. The Generating Facility must provide a primary response to variations in frequency. This has to be proportional to the deviation of the nominal frequency, similar to a governor response for its conventional generator. The reason for the frequency variation response has to be 5% or lesser, which is the slope used in conventional generators. This reason has to be determined with the nominal AC capacity of Generating Facility. The Generating Facility has to provide, as a minimum, positive and negative frequency variation response until 0.3 Hz beyond dead band of 0.02% or 0.012 Hz.~~

~~B. Where Energy Storage systems are used, the design has to contemplate, as a minimum, a useful energy for situations in which the frequency decrease equivalent to a 10% response of the nominal capacity AC by nine minutes and take a minute to reduce this participation at the rate of 10 per cent of the capacity AC per minute. The design has to contemplate this same Energy Storage capacity for when the frequency increases. The operational range of the Generating Facility to frequency response has to be from 10% to 100% capacity AC of the Generating Facility.~~

~~C. For Microgrids, the requirements in subsection A and B apply to any individual Generating Facility with a Nameplate Rating above 1 MW.~~

~~SECTION 1.58. Accessible Disconnect Switch~~

~~The EPS Operator must not require the installation of an accessible manual disconnect switch for inverter-based Generating Facilities with a Nameplate Rating of up to 300 kW. If an Interconnection Customer elects not to install an accessible disconnect switch,~~

Commented [A29]: [See TIR, Section 4 General Technical Requirements, Art 4.2 Isolation Device]

~~the EPS Operator may disconnect electric service to the Host Load if the EPS Operator must take the Generating Facility offline. The EPS Operator may require an accessible disconnect switch for Generating Facilities with Nameplate Rating greater than 300 kW. The features required for this disconnect switch are:~~

~~A. Be visible and accessible to the EPS Operator personnel twenty-four hours a day, seven days a week, without requiring the presence of the Interconnection Customer or equipment operator. If it is not accessible to EPS Operator's personnel, the Interconnection Customer must permit and facilitate access to the disconnect switch with previous coordination from EPS Operator personnel as required.~~

~~B. Be appropriate for the voltage levels of the installation.~~

~~C. Be able to interrupt the current flow to which it will be exposed. The disconnect switch need not be rated for load breaking, as long as it is installed combined with an automatic switch or other device capable of interrupting current flow.~~

~~D. Have provision for ensuring that it remains open or closed with EPS Operator padlock.~~

~~E. Able to open all poles simultaneously.~~

~~F. Be able to withstand inclement weather (weatherproof).~~

~~G. Be labeled with the phrase: "CAUTION – DG MANUAL INTERRUPTOR. DO NOT TOUCH TERMINALS AT BOTH ENDS; THEY COULD BE ENERGIZED". In addition, it must identify open and closed positions.~~

~~H. When operating, the accessible disconnect switch only disconnects the Generating Facility from the EPS, without interrupting electrical service from the EPS to the Host Load.~~

~~I. For Microgrids, the requirement for the manual switch applies to any individual Generating Facility with a Nameplate Rating greater than 300 kW. The switch(es) shall be placed at the individual Generating Facility as described in subsection H.~~

~~SECTION 1.59. Additional Requirements for Microgrids~~

Commented [A30]: [See TIR Section 13 Microgrids, TBD]

~~A. Additional technical requirements for Microgrids with two or more customers may be required by the EPS Operator to protect EPS equipment where that equipment is utilized during Islanded operation.~~

B. ~~Additional technical requirements for Microgrids with more than one Point of Common Coupling may be required by the EPS Operator.~~[12]

NET ENERGY METERING

SECTION 1.60. Participation in Net Metering Programs

A. A Generating Facility fueled by Renewable Energy Sources may participate in net metering if the Interconnection Application includes a request to participate in one of the following Net Metering Programs: the Basic Net Metering Program, the Aggregate Net Metering Program and the Shared Net Metering Program.

B. **Energy Storage Paired with Net Metering Systems**

(1) While an Energy Storage device may be paired with a Net Metering System, an Energy Storage device standing alone does not qualify as a Net Metering System.

(2) When an Energy Storage Device is paired with a Net Metering System, the Generating Facility shall be programmed with one or both of the following operating restrictions:

(i) Restricted from exporting electricity to the Electric Power System, beyond Inadvertent Export, and/or

(ii) Restricted to being charged solely from the customer's Net Metering System and not from the Electric Power System.

(3) An election to operate an Energy Storage Device with an operating restriction shall be identified in the Application, including a description of the operating restriction.

(4) A signed attestation of the operating restriction shall be provided by the Operator of the Energy Storage Device.

(5) The customer may propose to modify the operating restriction by submitting a revised attestation to the EPS Operator. The EPS Operator must approve the proposed revision in writing; approval shall not be unreasonably withheld or delayed.

[12] For example, coordination between multiple disconnection devices may be required to safely isolate the Microgrid from the EPS.

SECTION 1.61. Basic Net Metering Program

A. In the Basic Net Metering Program, a Generating Facility connected to the Distribution System shall have a maximum installed AC capacity of 25 kW for residential customers and 1 MW for commercial, governmental, industrial, agricultural, educational institutions and hospital medical facilities. Generating Facilities connected to the subtransmission or transmission systems shall have a maximum installed AC capacity of 5 MW for commercial customers, governmental, industrial, agricultural, educational institutions and hospital medical facilities.

SECTION 1.62. Aggregate Net Metering Program

A. The Aggregate Net Metering Program applies only to governmental Entities and non-profit academic institutions.

B. For customers with service on distribution voltages, the maximum installed AC capacity of the Generating Facility must be 1 MW. For customers with service on transmission or subtransmission voltages, the maximum installed AC capacity of the Generating Facility must be 5 MW.

C. All locations with service agreements that take advantage of this program must be included in the same account.

D. The locations may be interconnected to primary distribution, secondary distribution, subtransmission, or transmission systems. However, all participating locations must receive service at the same voltage level.

E. The service agreements to which the energy is to be accredited must be (1) within the same location where the Generating Facility is installed or (2) in other locations interconnected to the same power line at a distance not greater than two miles from the Generating Facility.

F. The Agreement to interconnect the GD and participate in this program will be effective thirty days after the first-rate revision established in Law 57, as amended.

SECTION 1.63. Shared Net Metering Program

A. The Shared Net Metering Program applies exclusively to residential and commercial customers with primary and secondary voltage distribution services under the horizontal property regime, such as residential, commercial or mixed-use condominiums. This Program also applies to public housing managed by the Department of Housing.

B. The location of the service agreements to which the energy is to be accredited must be within the same location where the Generating Facility is installed.

C. All service agreements must be serviced from the same point of delivery to which the Generating Facility is interconnected. The point of delivery can be the interconnection transformer in secondary distribution systems or the private substation in primary distribution systems.

D. For residential cases, the maximum capacity of the Generation Facility is 25 kW per participating customer or the capacity of the Interconnection Transformer, whatever smaller, up to a maximum of 1 MW.

E. For commercial or mixed use cases, the maximum capacity of the Generating Facility is the same as the capacity of the Interconnection Transformer, up to a maximum of 1 MW.

F. As required by these regulations, the owner of the Generating Facility must sign an Interconnection Agreement with the EPS Operator and Participate in the Net Metering Program. The owner of the Generating Facility can be the Board of Owners, the Owners Association, the owner of the building or any natural or legal entity with similar functions.

G. Each participating customer that is not the owner of the Generating Facility must sign an Agreement for Participation in the Shared Net Metering Program (see Attachment 9).

SECTION 1.64. Energy Compensation for Customers that Participate in the Net Metering Programs

Energy exported by the customer shall be compensated as described below; except in those cases in which any federal law or regulation expressly and specifically orders otherwise:

A. Energy compensation will be effective at the beginning of the billing period after the installation or configuration of the meter.

B. For each billing period, the EPS Operator will measure the energy that the customer consumes from and the energy that the customer exports to the EPS.

C. If during a billing period, the EPS Operator supplies the customer more energy that the customer exports, the customer will be charged for their Net Consumption.

D. If during a billing period, the customer exports more energy than supplied by the EPS Operator, the customer will be charged the minimum invoice amount corresponding to the rate at which the service is being received. The minimum invoice is the amount that the EPS Operator charges a customer who does not consume electricity during a billing period. The EPS Operator shall register an excess in exported energy during any billing period up to a daily maximum of 300 kWh for residential customers and 10 MWh for commercial customers connected to the Distribution System. For customers connected to the Transmission System, any excess in exported energy during a billing period will be registered up to a daily maximum of 50 MWh. The excess in exported energy will be carried over to the invoice for the next billing period.

E. Any excess in exported energy, that the customer accumulates during the year and that has not been used by the close of the June billing period of each year, will be compensated as described below:

(1) The EPS Operator shall use the greater of (a) ten cents per kilowatt-hour or (b) the price per kilowatt-hour that results from converting the average of the total price charged to customers throughout the year and subtracting the average of the fuel and power purchase adjustments.

(2) The customer will receive a credit on their monthly bill equal to 75% of the surplus energy and the remaining 25% of the surplus energy will be credited to the power bill of the Department of Education.

F. For customers who participate in the **Aggregate Net Metering Program**, besides paragraphs A to E of this Section, the following applies:

(1) Service agreements at the same location: The maximum amount of energy to be credited to all participating service agreements at the location where the Generating Facility is installed may be up to 100% of the consumption of all the service agreements. This energy will be credited first to the service agreement associated with the Generating Facility and the excess will be credited equally to the rest of the service agreements on the same account.

(2) Service agreements at different locations: The maximum amount of energy to be credited to all participating service agreements may be up to 120% of the consumption of the service agreements at the location where the Generating Facility is installed. This energy will be credited first to the service agreement associated with the Generating Facility and the excess will be credited equally to the rest of the service agreements, up to 100% of the consumption of the service agreements within the location where the Generating Facility is installed and the remaining 20% of the energy production will be credited equally to the service agreements in the other locations on the same account.

G. For customers participating in the **Shared Net Metering Program**, besides the provisions of paragraphs A to E of this Section, 100% of the energy produced by the Generating Facility will be credited equally among all participants of this program.

DISPUTE RESOLUTION

H. The Parties agree to attempt to resolve all disputes arising out of the interconnection process and associated studies and Interconnection Agreements according to this Article.

I. If a dispute occurs, the disputing Party shall provide the other Party a written Notice of Dispute containing the relevant known facts pertaining to the dispute, the specific dispute and the relief sought, and express notice by the disputing Party it is invoking the procedures under this Article. The notice shall be sent to the non-disputing Party's email address and physical address in the Interconnection Agreement or Interconnection Application, if there is no Interconnection Agreement. A copy of the notice shall also be sent to the Interconnection Ombudsperson at the Energy Bureau.

The non-disputing Party shall acknowledge the notice within three (3) Business Days of its receipt and identify a representative with the authority to decide for the non-disputing Party regarding the dispute.

J. If the dispute is principally related to one or both Parties' compliance with timelines specified in these Regulations or associated agreements, the Parties shall seek assistance from the Interconnection Ombudsperson if the Parties cannot mutually resolve the dispute within eight (8) Business Days.

K. If the dispute is not principally about one or both Parties' compliance with a timeline, then the non-disputing Party shall provide the disputing Party with all relevant regulatory and/or technical details and analysis regarding any interconnection requirements under dispute within ten (10) Business Days of the date of the notice of dispute. The confidentiality provisions of Section 1.43~~Section 5.08~~1.43 apply here. Within twenty (20) Business Days of the date of the notice of dispute, the Parties' authorized representatives will have to meet and confer to try to resolve the dispute. Parties shall operate in good faith and use best efforts to resolve the dispute.

L. If a resolution is not reached in thirty (30) Business Days from the date of the notice, either:

(1) A Party may request to continue negotiations for an additional twenty (20) Business Days;

(2) The Parties may by agreement make a written request for mediation to the Interconnection Ombudsperson; or

(3) Both Parties by agreement may request mediation from an outside third-party mediator with costs to be shared equally between the Parties.

M. If the results of the mediation are not accepted by one or more Parties and there is still disagreement, the dispute shall proceed to the Energy Bureau's process for reconsideration in accordance with Article 11.

N. At any time, either Party may request reconsideration by the Energy Bureau in accordance with Article 11.

PENALTIES

O. Anyone who infringes this Regulation or who alters all or part the EPS or an electric installation in a manner such that the operation of a Generating Facility or Microgrid cannot be accurately monitored including, but not limited to, its bi-directional energy flow shall be penalized by the EPS Operator and/or Energy Bureau with the corresponding administrative sanctions and penalties established in Act 83-1941 and Act 57-2014 and the regulations adopted pursuant to the same.

P. The EPS Operator is authorized to investigate matters regarding the interconnection of Microgrids with the EG, including the veracity of the information stated in the certifications, inspection reports and any other documents filed with the EPS Operator under this Regulation and can take the appropriate actions (administrative and judicial) authorized by laws.

Q. If the EPS Operator and/or Energy Bureau, as applicable, determines that a Generating Facility or Microgrid was interconnected in violation of applicable legal provisions, or detects any irregularity, deficiency, omission or fraud in the certifications filed, the EPS Operator and/or Energy Bureau, as applicable, may impose the administrative sanctions established in Act 83-1941 and Act 57-2014, to the professional responsible of such violation and to refer the professional to the pertinent professional association, to the Public Energy Policy Program of the Department of Economic Development and Commerce for the corresponding disciplinary action.

PUBLIC REPORTING AND RECORD RETENTION

SECTION 1.65. Public Queue

The EPS Operator shall maintain a public interconnection queue pursuant to Section 1.26~~Section 2.09~~1.26 on its website in a tabular format, *i.e.*, a sortable spreadsheet, which it shall update on at least a ~~monthly~~quarterly basis. The date of the most recent update shall be clearly indicated. The public queue should include, at a minimum, the following information about each Interconnection Application, where available:

A. Queue Position, *i.e.*, queue number

B. Nameplate Rating

Commented [A31]: LUMA assumes the purpose of this is to provide information to the public. LUMA suggests a more automated and integrated approach to reporting that is more functional and informative to the end user.

The currently proposed reporting structure requires manual updates which would create undue reporting burden and additional costs without providing additional transparency versus an automatic and integrated approach.

C. Export Capacity

D. Primary fuel type (*e.g.*, solar, wind, bio-gas, etc.)

E. Secondary fuel type (if applicable)

F. Exporting or Non-Exporting

G. City

H. Zip code

I. Substation

J. Feeder

K. Status (active, withdrawn, interconnected, etc.)

L. Date application deemed complete

M. Date of notification of Fast Track screen results, if applicable

N. Fast Track Screen results, if applicable (pass or fail, and if fail, identify the screens failed)

O. Date of notification of supplemental review results, if applicable

P. Supplemental review results, if applicable (pass or fail, and if fail, identify the screens failed)

Q. Date of notification of feasibility study results, if applicable.

R. Date of notification of system impact study results, if applicable

S. Date of notification of Transmission System impact study results, if applicable

T. Date of notification of Facilities Study results and/or construction estimates, if applicable

U. If upgrades were needed, the estimated and final cost of the upgrades

SECTION 1.66. Annual Interconnection Report

By April 1 of each year, the EPS Operator shall submit to the Energy Bureau and publish on its website a report on Interconnection Applications reviewed in the past calendar year, including:

A. The number, Nameplate Rating, and Export Capacity of completed Interconnection Applications for Generating Facilities and Microgrids received, approved, studied, installed, withdrawn, and denied under the Simplified Process, the Fast Track Process, and the Study Process.

B. The fuel type, number, Nameplate Rating, and Export Capacity of Generation Facilities and Microgrids approved for interconnection.

C. The fuel type, number, Nameplate Rating, and Export Capacity of all Generation Facilities and Microgrids currently interconnected to the EPS.

D. A narrative description of the data provided, including any trends identified by the EPS Operator.

E. The underlying data in tabular format, *i.e.*, a searchable spreadsheet.

SECTION 1.67. Record Retention

A. The EPS Operator shall maintain the records and reports specified in this Article for at least five years.

B. The EPS Operator shall retain copies of studies it performs to determine the feasibility of, Distribution system impacts of, Transmission System impacts of, or facilities required by a proposed interconnection.

RECONSIDERATION AND JUDICIAL REVIEW

SECTION 1.68. Reconsideration

A. Any person who is not satisfied with a decision made by the EPS Operator under this Regulation may first follow the process identified in Article 8, or may file, within the term of twenty (20) days from the date copy of the notice of such decision is filed by the Energy Bureau's Clerk, a request for reconsideration before the Energy Bureau wherein the petitioner sets forth in detail the grounds that support the request and the decisions that, in the opinion of the petitioner, the Energy Bureau should reconsider.

B. Any person who is not satisfied with a decision made by the Energy Bureau under this Regulation may file, within the term of twenty (20) days from the date copy of the notice of such decision is filed by the Energy Bureau's Clerk, a request for reconsideration before the Energy Bureau wherein the petitioner sets forth in detail the grounds that support the request and the decisions that, in the opinion of the petitioner, the Energy Bureau should reconsider.

SECTION 1.69. Administrative Review

Any person who is not satisfied with a decision made by the EPS Operator under this Regulation may file, within the term of twenty (20) days from the date copy of the notice of such decision is issued and notified by the EPS Operator, a request for review before the Energy Bureau, pursuant to the provisions of Act 57-2014 and Regulation 8543.

SECTION 1.70. Judicial Review

Any person dissatisfied with a final decision of the Energy Bureau under this Regulation may, within thirty (30) days from the date copy of notice of a final decision addressing a request for reconsideration is filed by the Energy Bureau's Clerk, or within thirty (30) days from the date a copy of the notice of an Energy Bureau final decision is filed by the Energy Bureau's Clerk, if a request for reconsideration has not been filed, appear before the Puerto Rico Court of Appeals by way of writ of judicial review.

ATTACHMENT 1
GENERATOR INTERCONNECTION APPLICATION

Commented [A32]: LUMA continues to review these attachments and notes that certain attachments are missing (Attachment 2, 5, 8 and 9)

(Application Form)

PREPA Designated Contact Person: ____

Address: ____

Telephone Number: ____

E-Mail Address: ____

Preamble. An Interconnection Application is considered complete when it provides all applicable and correct information required below. \

Filing Instructions: An Interconnection Customer who requests interconnection must submit this Interconnection Application by [to be filled in with Cyber Portal submittal details].

Processing Fee or Deposit:

- *Fast Track Process* If the Interconnection Application is submitted under the Fast Track Process, the non-refundable processing fee is $100 plus $1.00 per kW of Microgrid capacity.
- *Study Process* - If the Interconnection Application is submitted under the Study Process, whether a new submission or an Interconnection Application that did not pass the Fast Track Process, the Interconnection Customer shall submit to PREPA a deposit not to exceed $1,000 plus $2.00 per kW of Microgrid capacity towards the cost of the first study.
- Additional fees or deposits shall not be required, except as otherwise specified in the Microgrid Interconnection Regulations.

Interconnection Customer Information:

Legal Name of the Interconnection Customer (or, if an individual, individual's name)

Name: ____

Contact Person: ____

Mailing Address: ____

City: _________________________ State:_____________ Zip:__________

Facility Location (if different from above):________________________________

____.

Telephone (Day): _______________ Telephone (Evening): ______________

E-Mail Address: _____________________

Alternative Contact Information (if different from the Interconnection Customer)

Contact Name: ____

Title: ____

Address:____

____.

Telephone (Day): ______________ Telephone (Evening):_______________

E-Mail Address: ___________________

Application is for: ☐ New Microgrid ☐ Capacity addition to Existing Microgrid

If capacity addition to existing facility, please describe: ______________________________

____.

Will the Microgrid be used for any of the following?

Net Metering? Yes ☐ No ☐

To Export Power across the POI? Yes ☐ No ☐

For installations at locations with existing electric service to which the proposed Microgrid will interconnect, provide the Existing Account Number(s) (provide all accounts to be included within the Microgrid):____

____.

Contact Name: ____

Title: ____

Address: ____

____.

Telephone (Day): _________________ Telephone (Evening): _______________

E-Mail Address: ________________________

Requested Point of Common Coupling (describe or provide coordinates):

____

____

Interconnection Customer's Requested In-Service Date: ___________________________

<u>Microgrid Information</u>[13]:

Energy Source(s): (check those that apply)

Solar	☐
Wind	☐
Energy Storage	☐
	Identify type (*e.g.*, lithium ion battery): ____.
Hydro	☐
	Identify type: ____.
Diesel	☐
Natural Gas	☐
Fuel Oil	☐
Other	☐
	_______________________________________.

Prime Mover(s): (check those that apply)

Fuel Cell	☐
Recip Engine	☐
Gas Turbine	☐
Steam Turbine	☐
Microturbine	☐
PV	☐
Other	☐
	_______________________________________.

Type of Generator(s) (check all that apply): ☐ Synchronous ☐ Induction ☐ Inverter

Aggregate Generator Nameplate Rating: __________kW (Typical).

[13] Data apply only to the Microgrid, not the Interconnection Facilities.

Aggregate Generator Nameplate kVAR: ___________.

Interconnection Customer or Customer-Site/Microgrid Load: ______________kW (if none, so state)

Typical Reactive Load (if known): ______________

Maximum Physical Export Capability Requested: ____________ kW

List components of the Microgrid or Generating Facility equipment currently certified:

	Equipment Type	Certifying Entity
1.	_________________________	_________________________
2.	_________________________	_________________________
3.	_________________________	_________________________
4.	_________________________	_________________________
5.	_________________________	_________________________

If a certified protective relay package is used with any Generating Facility, is the prime mover compatible with the relay package? ☐ Yes ☐ No

Generator (or solar module) Manufacturer, Model Name & Number: _______________

Version Number: _______________

Nameplate Output Power Rating in kW: ____________

Nameplate Output Power Rating in kVA: ____________

Individual Generator Power Factor

Rated Power Factor: Leading: ___________Lagging: _____________

Total Number of Generators in wind farm to be interconnected pursuant to this

Interconnection Application: ________ Elevation:____ ☐ Single phase ☐ Three phase

Inverter Manufacturer, Model Name & Number (if used):__________________________

List of adjustable set points for the Generating Facility(s) protective equipment or software (provide for all Generating Facilities in Microgrid): __________________

List of adjustable set points for the Microgrid interface protective equipment or software (provide for all interfaces that apply): __________________

Note: A completed Power Systems Load Flow data sheet must be supplied with the Interconnection Application.

<u>Generating Facility Characteristic Data (for inverter-based machines)</u>

Max fault current: ☐ Instantaneous ☐ RMS?

Generating Facility Characteristic Data (for rotating machines)

RPM Frequency: ___________

(*) Neutral Grounding Resistor (If Applicable): __________

Synchronous Generators:

Direct Axis Synchronous Reactance, X_d: ______ P.U.
Direct Axis Transient Reactance, X'_d: _________P.U.
Direct Axis Subtransient Reactance, X''_d: ____________P.U.
Negative Sequence Reactance, X_2: ________ P.U.
Zero Sequence Reactance, X_0: __________ P.U.
KVA Base: _____________
Field Volts: _____________
Field Amperes: __________

Induction Generators:

Motoring Power (kW): ____________
I22t or K (Heating Time Constant): ____________
Rotor Resistance, Rr: ____________
Stator Resistance, Rs: ____________
Stator Reactance, Xs: ____________
Rotor Reactance, Xr: ____________
Magnetizing Reactance, Xm: ____________
Short Circuit Reactance, Xd'': ____________
Exciting Current: ____________
Temperature Rise: ____________
Frame Size: ____________
Design Letter: ____________
Reactive Power Required In Vars (No Load): ____________
Reactive Power Required In Vars (Full Load): ____________
Total Rotating Inertia, H: ____________ Per Unit on kVA Base

Note: Please contact PREPA before submitting the Interconnection Application to determine if the specified information above is required.

Excitation and Governor System Data for Synchronous Generators Only

If required, provide appropriate IEEE model block diagram of excitation system, governor system and power system stabilizer (PSS) in accordance with PREPA criteria. A PSS may be determined to be required by applicable studies. A copy of the manufacturer's block diagram may not be substituted.

Interconnection Facilities Information

Will a transformer be used between the Microgrid and the Point of Common Coupling? __Yes __No

Will the transformer be provided by the Interconnection Customer? ___Yes ___No

Transformer Data (If Applicable, for Interconnection Customer-Owned Transformer):

Is the transformer: ___single phase ____three phase? Size: _________kVA

Transformer Impedance: ______% on ________kVA Base

If Three Phase:

Transformer Primary: ____ Volts ____ Delta ____Wye ____ Wye Grounded

Transformer Secondary: ____ Volts ____ Delta ____Wye ____ Wye Grounded

Transformer Tertiary: ____ Volts ____ Delta ____Wye ____ Wye Grounded

Transformer Fuse Data (If Applicable, for Interconnection Customer-Owned Fuse):

(Attach copy of fuse manufacturer's Minimum Melt and Total Clearing Time-Current Curves)

Manufacturer: _______________ Type: _____________ Size: _____ Speed: ________

Interconnecting Circuit Breaker (if applicable):

Manufacturer: _______________________ Type: _________

Load Rating (Amps): _____ Interrupting Rating (Amps): ______ Trip Speed (Cycles): _____

Interconnection Protective Relays (If Applicable):

If Microprocessor-Controlled:

List of Functions and Adjustable Setpoints for the protective equipment or software:

	Setpoint Function	Minimum	Maximum
1.	___________________	______	______
2.	___________________	______	______
3.	___________________	______	______
4.	___________________	______	______
5.	___________________	______	______
6.	___________________	______	______

If Discrete Components:

(Enclose Copy of any Proposed Time-Overcurrent Coordination Curves)

Manufacturer:___________	Type:___	Style/Catalog No.:____	Proposed Setting:_____
Manufacturer:___________	Type:___	Style/Catalog No.:____	Proposed Setting:_____
Manufacturer:___________	Type:___	Style/Catalog No.:____	Proposed Setting:_____
Manufacturer:___________	Type:___	Style/Catalog No.:____	Proposed Setting:_____

Manufacturer:___________ Type:____ Style/Catalog No.:_____ Proposed Setting:_____

Current Transformer Data (If Applicable):
(Enclose Copy of Manufacturer's Excitation and Ratio Correction Curves)

Manufacturer: ____

Type: _________________ Accuracy Class: ____ Proposed Ratio Connection: ________

Manufacturer: ____

Type: _________________ Accuracy Class: ____ Proposed Ratio Connection: ________

Potential Transformer Data (If Applicable):

Manufacturer: ____

Type: _________________ Accuracy Class: ____ Proposed Ratio Connection: ________

Manufacturer: ____

Type: _________________ Accuracy Class: ____ Proposed Ratio Connection: ________

General Information

Enclose copy of site electrical one-line diagram showing the configuration of all Microgrid equipment, current and potential circuits, and protection and control schemes. The one-line diagram shall include:

- Interconnection Customer name.
- Application ID.
- Installer name and contact information.
- Install location(s).
- Correct positions of all equipment, including but not limited to panels, inverter, and DC/AC disconnect, including distances between equipment, and any labeling found on equipment.

o Equipment labels must meet minimum NEC or NESC labeling requirements. Labels should be durable and permanently attached, such as engraved or etched plastic, which can be riveted or adhered to the device.

    - If required for the Generating Facilities, a visible, lockable and accessible AC disconnect must be installed and located according to 8915 section IV.B.13 or 8916 section V.B.15.

- Meter information, including amp rating and service voltage
- Production Meter wiring, either:
    - 1-Phase, 3 Wire; or
    - 3-Phase, 4-Wire

This one-line diagram must be signed and stamped by a licensed Professional Engineer if the Microgrid is larger than 1 MW.

Is One-Line Diagram Enclosed? ☐ Yes ☐ No

Enclose copy of any site documentation that indicates the precise physical location of the proposed Microgrid (e.g., USGS topographic map or other diagram or documentation).

Proposed location of protective interface equipment on property (include address if different from the Interconnection Customer's address)____________________________________

Enclose copy of any site documentation that describes and details the operation of the protection and control schemes of the Microgrid interface. If the Microgrid contains portions of PREPA's EPS, provide documentation on details of Islanded operation as well.

Is Available Documentation Enclosed? ☐ Yes ☐ No

Enclose copies of schematic drawings for all protection and control circuits, relay current circuits, relay potential circuits, and alarm/monitoring circuits (if applicable).
Are Schematic Drawings Enclosed? ☐ Yes ☐ No

Professional Engineer[14] Certification

I hereby certify that the Microgrid meets the specifications established through regulations by the Bureau for this Microgrid and that the same was completed according to the laws, regulations, and rules applicable to the interconnection of microgrids into the distribution and transmission system.

Professional Engineer: ________________________________ Date: __________
Interconnection Customer Signature

[14] The Professional Engineer must be duly licensed engineer to practice the profession in Puerto Rico.

I hereby certify that, to the best of my knowledge, all the information provided in this Interconnection Application is true and correct.

For Interconnection Customer: ______________________________ Date: _________

ATTACHMENT 2
SIMPLIFIED INTERCONNECTION APPLICATION AND AGREEMENT

ATTACHMENT 3
CERTIFICATION CODES AND STANDARDS

Commented [A33]: This information will be referenced in the TIR and this Attachment will be removed.

The following Certification Codes and Standards will apply as these may be updated from time to time:

1) IEEE1547 Standard for Interconnecting Distributed Resources with Electric Power Systems (including use of IEEE 1547.1 testing protocols to establish conformity);
2) UL 1741 Inverters, Converters, and Controllers for Use in Independent Power Systems;
3) IEEE Std 929-2000 IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems;
4) NFPA 70 (2002), National Electrical Code;
5) IEEE Std C37.90.1-1989 (R1994), IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems;
6) IEEE Std C37.90.2 (1995), IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers;
7) IEEE Std C37.108-1989 (R2002), IEEE Guide for the Protection of Network Transformers;
8) IEEE Std C57.12.44-2000, IEEE Standard Requirements for Secondary Network Protectors;
9) IEEE Std C62.41.2-2002, IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000V and Less) AC Power Circuits;
10) IEEE Std C62.45-1992 (R2002), IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000V and Less) AC Power Circuits;
11) ANSI C84.1-1995 Electric Power Systems and Equipment – Voltage Ratings (60 Hertz);
12) IEEE Std 100-2000, IEEE Standard Dictionary of Electrical and Electronic Terms
13) NEMA MG 1-1998, Motors and Small Resources, Revision 3;
14) IEEE Std 519-1992, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems; and
15) NEMA MG 1-2003 (Rev 2004), Motors and Generators, Revision 1

ATTACHMENT 4
CERTIFICATION OF GENERATOR EQUIPMENT PACKAGES

1.0 Generating Facilities or Microgrid equipment proposed for use separately or packaged with other equipment in an interconnection system shall be considered certified for interconnected operation if (1) it has been tested in accordance with industry standards for continuous utility interactive operation in compliance with the appropriate codes and standards referenced below by any Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration to test and certify interconnection equipment pursuant to the codes and standards in ATTACHMENT 3, (2) it has been labeled and is publicly listed by such NRTL at the time of the Interconnection Application, and (3) such NRTL makes readily available for verification all test standards and procedures it utilized in performing such equipment certification, and, with consumer approval, the test data itself. The NRTL may make such information available on its website and by encouraging such information to be included in the manufacturer's literature accompanying the equipment.

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

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

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

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

6.0 An equipment package does not include equipment provided by the EPS Operator.

7.0 Any equipment package approved and listed by the Puerto Rico Energy Bureau or another state agency for interconnected operation in the state before the effective date of these Generating Facility Microgrid Interconnection Regulations shall be considered certified under these Regulations for use in the state.

ATTACHMENT 5
FEASIBILITY STUDY AGREEMENT

ATTACHMENT 6
SYSTEM IMPACT STUDY AGREEMENT

THIS AGREEMENT is made and entered into this _____day of_____________20___ by and between____, a_________________________ organized and existing under the laws of Puerto Rico, ("Interconnection Customer,") and the Puerto Rico Electric Power Authority ("PREPA") a corporate entity existing under the laws of Puerto Rico. Interconnection Customer and PREPA each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Microgrid or generating capacity addition to an existing Microgrid consistent with the Interconnection Application completed by the Interconnection Customer on______________________; and

WHEREAS, the Interconnection Customer desires to interconnect the Microgrid with the Electric Power System;

WHEREAS, the Interconnection Customer has requested PREPA to perform a system impact study(s) to assess the impact of interconnecting the Microgrid with the Electric Power System, and of any Affected Systems;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 Consistency with Microgrid Interconnection Regulation. The Interconnection Customer elects and PREPA shall cause to be performed a system impact study(s) consistent with the Microgrid Interconnection Regulation.

2.0 Scope of the System Impact Study. The scope of a system impact study shall be subject to the assumptions set forth in Attachment A to this Agreement.

3.0 Basis for the System Impact Study. A system impact study will be based upon the technical information provided by Interconnection Customer in the Interconnection Application. PREPA reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the system impact study.

4.0 System Impact Study. A system impact study shall consist of a short circuit analysis, a stability analysis, a power flow analysis, voltage drop and flicker studies, protection and set point coordination studies, and grounding reviews, as necessary. A system impact study shall state the assumptions upon which it is based, state the results of the analyses, and provide the requirement or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. A system impact study shall provide a list of facilities required as a result of the Interconnection Application and non-binding good faith estimates of cost responsibility and time to construct.

5.0 Distribution System Impact Study. A distribution system impact study shall incorporate a distribution load flow study, an analysis of equipment interrupting ratings, protection coordination study, voltage drop and flicker studies, protection and set point coordination studies, grounding reviews, and the impact on Electric Power System operation, as necessary.

6.0 Queue. If PREPA uses a queuing procedure for sorting or prioritizing projects and their associated cost responsibilities for any required Network Upgrades, the system impact study shall consider all Generating Facilities and/or Microgrids (and regarding paragraph 8.3 below, any identified Upgrades associated with such higher queued interconnection) that, on the date the system impact study is commenced –

6.1. Are directly interconnected with the Electric Power System; or

6.2. Have a pending higher queued Interconnection Application to interconnect with the Electric Power System.

7.0 Deposit. A deposit of the equivalent of the good faith estimated cost of a distribution system impact study and the good faith estimated cost of a Transmission System impact study shall be required from the Interconnection Customer when the signed Agreement is provided to PREPA.

8.0 Basis of Study Fees. Any study fees shall be based on PREPA's actual costs and will be invoiced to the Interconnection Customer within twenty (20) Business Days after the study is completed and delivered and will include a summary of professional time.

9.0 Payment of Study Costs. The Interconnection Customer must pay any study costs that exceed the deposit without interest within twenty (20) Business Days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, PREPA shall refund such excess within twenty (20) Business Days of the invoice without interest.

10.0 Interpretations, Governing Law, Regulatory Authority, and Rules. When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the Microgrid Interconnection Regulations. The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the of Puerto Rico. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

11.0 Amendment. The Parties may amend this Agreement by a written instrument duly executed by both Parties.

12.0 No Third-Party Beneficiaries. This Agreement is not intended to and does not create rights, remedies, or benefits of any character for any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns.

13.0 Waiver.

13.1. The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

13.2. Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from PREPA. Any waiver of this Agreement shall, if requested, be provided in writing.

14.0 Multiple Counterparts. This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

15.0 No Partnership. This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

16.0 Severability. If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

17.0 Subcontractors. Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.

17.1. The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that PREPA shall not be liable for the actions or inactions of the Interconnection Customer or its subcontractors regarding obligations of the Interconnection Customer under this Agreement. Any obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

17.2. The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

18.0 <u>Inclusion of PREPA Tariffs and Rules</u>. The interconnection services provided under this Agreement shall be subject to the terms and conditions set forth in the tariff schedules and rules applicable to the electric service provided by PREPA, which tariff schedules and rules are hereby incorporated into this Agreement by this reference. Notwithstanding any other provisions of this Agreement, PREPA shall have the right to unilaterally file with the Bureau, pursuant to the Energy Bureau's rules and regulations, an application for change in rates, charges, classification, service, tariff, or rule or any agreement relating thereto. The Interconnection Customer shall also have the right to unilaterally file with the Energy Bureau, pursuant to the Bureau's rules and regulations, an application for change in rates, charges, classification, service, tariff, or rule or any agreement relating thereto. Each Party shall have the right to protest any such filing by the other Party and/or to participate fully in any proceeding before the Energy Bureau in which such modifications may be considered, pursuant to the Energy Bureau's rules and regulations.

IN WITNESS THEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

PREPA	**[Name of Interconnection Customer]**
Name (print): ______________________	Name (print): ______________________
Title: ______________________	Title: ______________________
Date: ______________________	Date: ______________________
Signature: ______________________	Signature: ______________________

Attachment A to System Impact Study Agreement

Assumptions Used in Conducting the System Impact Study

The system impact study shall be based upon the following assumptions:

1) Designation of Point of Common Coupling and configuration to be studied; and

2) Designation of alternative Points of Interconnection and configuration.

Items 1) and 2) are to be completed by the Interconnection Customer. Other assumptions (to be listed below) are to be provided by the Interconnection Customer and PREPA.

Assumptions:

ATTACHMENT 7
FACILITIES STUDY AGREEMENT

THIS AGREEMENT is made and entered into this ____day of____________, 20___ by and between ____, a ________________________ organized and existing under the laws of Puerto Rico, ("Interconnection Customer,") and the Puerto Rico Electric Power Authority ("PREPA") a corporate entity existing under the laws of the Commonwealth of Puerto Rico. Interconnection Customer and PREPA each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Microgrid or generating capacity addition to an existing Microgrid consistent with the Interconnection Application completed by the Interconnection Customer on___________________; and

WHEREAS, the Interconnection Customer desires to interconnect the Microgrid with the Electric Power System;

WHEREAS, PREPA has completed Fast Track, supplemental review, and/or a system impact study and provided the results of the review to the Interconnection Customer, or determined none was required; and

WHEREAS, the Interconnection Customer has requested PREPA perform a facilities study to specify and estimate the cost of the equipment, engineering, procurement and construction work needed to implement the conclusions of the above noted review in accordance with Good Utility Practice to physically and electrically connect the Microgrid with the Electric Power System.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

8.0 Scope of the Facilities Study. The Interconnection Customer elects and PREPA shall cause a Facilities Study consistent with the Microgrid Interconnection Regulation to be performed. The scope of the Facilities Study shall be subject to data provided in Attachment A to this Agreement.

9.0 Content of the Facilities Study. The Facilities Study shall specify and estimate the cost of the equipment, permitting, engineering, procurement and construction work (including overheads) needed to implement the conclusions of the system impact study(s). The Facilities Study shall also identify (1) the electrical switching configuration of the equipment, including, without limitation, transformer, switchgear, Meters, and other station equipment, (2) the nature and estimated cost of PREPA's Interconnection Facilities and Upgrades necessary to accomplish the interconnection, and (3) an estimate of the time required to complete the construction and installation of such facilities.

10.0 Minimization of Costs. PREPA may propose to group facilities required for more than one Interconnection Customer to minimize facilities costs through economies of scale, but any Interconnection Customer may require the installation of facilities required for its own Microgrid if it is willing to pay the costs of those facilities.

11.0 Deposit. A deposit of the good faith estimated facilities study costs shall be required from the Interconnection Customer and provided when the signed Agreement is provided to PREPA.

12.0 Basis of Study Fees. Any study fees shall be based on PREPA's actual costs and will be invoiced to the Interconnection Customer within twenty (20) Business Days after the study is completed and delivered and will include a summary of professional time.

13.0 Payment of Study Fees. The Interconnection Customer must pay any study costs that exceed the deposit without interest within twenty (20) Business Days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, PREPA shall refund such excess within twenty (20) Business Days of the invoice without interest.

14.0 Interpretation, Governing Law, Regulatory Authority, and Rules. When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the Microgrid Interconnection Regulations. The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the of Puerto Rico. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

15.0 Amendment. The Parties may amend this Agreement by a written instrument duly executed by both Parties.

16.0 No Third-Party Beneficiaries. This Agreement is not intended to and does not create rights, remedies, or benefits of any character for any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns.

17.0 Waiver.

17.1. The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

17.2. Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver regarding any other failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from PREPA. Any waiver of this Agreement shall, if requested, be provided in writing.

18.0 Multiple Counterparts. This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

19.0 No Partnership. This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

20.0 Severability. If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

21.0 Subcontractors. Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.

21.1. The creation of any subcontract relationship shall not relieve the hiring

Party of any of its obligations under this Agreement. The hiring Party shall be responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that PREPA shall not be liable for the actions or inactions of the Interconnection Customer or its subcontractors regarding obligations of the Interconnection Customer under this Agreement. Any obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

21.2. The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

22.0 Inclusion of PREPA Tariffs and Rules. The interconnection services provided under this Agreement shall be subject to the terms and conditions set forth in the tariff schedules and rules applicable to the electric service provided by PREPA, which tariff schedules and rules are hereby incorporated into this Agreement by this reference. Notwithstanding any other provisions of this Agreement, PREPA shall have the right to unilaterally file with the Bureau, pursuant to the Energy Bureau's rules and regulations, an application for change in rates, charges, classification, service, tariff, or rule or any agreement relating thereto. The Interconnection Customer shall also have the right to unilaterally file with the Energy Bureau, pursuant to the Bureau's rules and regulations, an application for change in rates, charges, classification, service, tariff, or rule or any agreement relating thereto. Each Party shall have the right to protest any such filing by the other Party and/or to participate fully in any proceeding before the Energy Bureau in which such modifications may be considered, pursuant to the Energy Bureau's rules and regulations.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or representatives on the day and year first above written.

PREPA	**[Name of Interconnection Customer]**
Name (print): ____________________________	Name (print): ____________________________
Title: ____________________________________	Title: ____________________________________
Date: ____________________________________	Date: ____________________________________
Signature: ________________________________	Signature: ________________________________

Attachment A to Facilities Study Agreement
Data to Be Provided by the Interconnection Customer
with the Facilities Study Agreement

Provide location plan and simplified one-line diagram of the plant and station facilities. For staged projects, please indicate future generation, transmission circuits, etc.

1) On the one-line diagram, indicate the generation capacity attached at each Metering location. (Maximum load on CT/PT); and
2) On the one-line diagram, indicate the location of auxiliary power. (Minimum load on CT/PT) Amps

One set of Meters is required for each generation connection to the new ring bus or existing PREPA station. Number of generation connections: ____________

Will an alternate source of auxiliary power be available during CT/PT maintenance?

Yes ____ No ____

Will a transfer bus on the generation side of the Metering require that each Meter set be designed for the total plant generation? Yes ____ No ____
(Please indicate on the one-line diagram).

What type of control system or PLC will be located at the Microgrid?

____

____

What protocol does the control system or PLC use?

____

____

Please provide a 7.5-minute quadrangle map of the site. Indicate the plant, station, transmission line, and property lines.

Physical dimensions of the proposed interconnection station:

____

Bus length from generation to interconnection station:

____

Line length from interconnection station to the Transmission System.

____

Tower number observed in the field. (Painted on tower leg)[15]:

____

Number of third-party easements required for transmission lines[16]:

____

Please provide the following proposed schedule dates:

Commencement of Construction	Date: ________________
Generator step-up transformers receive back feed power	Date: ________________
Generation Testing	Date: ________________
Commercial Operation	Date: ________________

[15] To be completed in coordination with PREPA.

[16] *Id*.

ATTACHMENT 8
INTERCONNECTION AGREEMENT

ATTACHMENT 9
AGREEMENT FOR PARTICIPATION IN THE SHARED NET METERING PROGRAM

Exhibit 2

Preliminary Draft of Technical Interconnection Requirements Document

LUMAPR.COM

Technical Interconnection Requirements - DRAFT

VERSION HISTORY:

Version	Date	Description
0.1	11/14/2021	Initial Draft

Table of Contents

List of Tables

1. Introduction

1.1 Scope

This Technical Interconnection Requirements (TIR) document provides guidance for grid interconnection and Parallel Operation with the grid in the EPS. It provides criteria for LUMA engineers, as well as customers and developers planning to interconnect distributed energy resources (DERs) with the EPS. DERs can be gas or diesel generators, inverter-connected PV, energy storage, fuel cells, microturbines and other configurations or combinations of the above (e.g., virtual power plants (VPPs)). Both Transmission and Distribution connections are covered. Specific Transmission and Sub-transmission Requirements are found in the Transmission and Sub-transmission section of this TIR. The requirements in this document apply to all aspects of DER connection and operation with the grid.

The document addresses responsibilities of the Interconnecting Customer (IC) related to the grid integration, point of connection, and general system performance. It includes operational performance, power quality, protection, monitoring, control, and telemetry requirements. Interoperability with other grid equipment as well as metering, commissioning test and verification requirements are addressed. The document also covers specific operating requirements and any special protection that may be required for connections on radial or network locations in the distribution grid.

1.2 Responsibilities

1.2.1 Customer-Owned Generating Equipment

The Interconnection Customer is responsible for designing, installing, operating, and maintaining its' own equipment in accordance with interconnection agreements and applicable standards, including IEEE Standard 1547, the National Electrical Code, other Safety Codes, and all applicable laws, statutes, guidelines, and regulations. This includes installing, setting, and maintaining all protective devices necessary for safe grid integration and to protect the IC's and the EPS facilities.

1.2.2 LUMA Managed and Operated Distribution System

Requirements specified in these DER requirements are also intended to complement LUMA efforts and responsibility to maintain distribution grid safety, power quality and reliability. Continuity and quality of service to all customers is a key responsibility of LUMA.

1.2.3 Requirements Related to Ongoing EPS Upgrades

The EPS is constantly changing due to shifts in loading and the addition or removal of generation. The possibility exists that a change in the EPS may cause a change in the protection or other requirements at the generation interconnection. It would then be the responsibility of the generator owner to make the necessary changes to meet these changing grid requirements.

2. Definitions and Acronyms

2.1 Definitions

For purposes of this TIR, the following terms will have the meaning established below, except when the context of the content of any provision clearly indicates otherwise. Technical terminology used in this document is intended to follow definitions and usage in IEEE Standard 1547™-2018 and other related IEEE, IEC, and ANSI standards. Capitalized terms not defined in this document will have the definition set forth in the Puerto Rico Energy Bureau's Generating Facility and Microgrid Interconnection Regulation then in effect.

A few definitions are provided here for convenience or if unique to this document.

- ***Account*** *– An account is one metered rate or service classification which normally has one electric delivery point of service. Each account shall have only one electric service supplier providing full electric supply requirements for that account. A premise may have more than one account.*

- ***Company –LUMA ENERGY SERVCO, LLC****, a limited liability company organized under the laws of the Commonwealth of Puerto Rico ("**LUMA**" or "**Operator**") under the terms of the Operation and Maintenance Agreement dated as of June 22, 2020, as amended from time to time in accordance with its terms (including any amendments as may be contemplated by the Supplemental Agreement (as defined in Exhibit F-1 to such agreement)) (collectively the "**OMA**"). LUMA is the Operator of the Electric Power System.*

- ***Buffer zones*** *– Are limits, defined and used to protect the grid by providing a safety margin added to DER integration limits, for example, limits to prevent reverse power on a substation power transformer.*

- ***Customer*** *– Any adult person, partnership, association, corporation, or other entity: (i) in whose name a service account is listed, (ii) who occupies or is the ratepayer for a premise, building, structure, etc., and (iii) who is primarily responsible for payment of bills. A Customer includes anyone taking Delivery Service or combined Electric Supply & Delivery Service from the Company under one service classification for one account, premise, or site. Multiple premises or sites under the same name are considered multiple Customers.*

- ***Control Center(s)*** *– EPS Operator department that monitors and has direct control over the operation of the EPS. The Transmission and Distribution Systems are managed by separate Control Centers.*

- ***Distribution System - or Network –*** *The physical equipment used to distribute electric power at voltages below 38,000 volts, including but not limited to poles, primary lines, secondary lines, service drops, transformers and Meters.*

- ***Distributed Energy Resource (DER) –*** *DER includes both generators and energy storage technologies capable of exporting active power to an EPS.*

- ***Electric Power System (EPS) –*** *The Puerto Rico electric power Transmission and Distribution System, excluding equipment owned by Interconnection Customers.*

- ***Energy Bureau*** *– The Puerto Rico Energy Bureau, established by virtue of the Reorganization Plan of the Puerto Rico Public Service Regulatory Board, and Act No. 211-2018, known as the Reorganization Plan Execution Act of the Public Service Regulatory Board, formerly the Puerto Rico Energy Commission created under Act 57-2014, which is a specialized independent entity in charge of regulating, overseeing, and enforcing the public policy on energy of the Government of Puerto Rico.*

- ***Facility*** *(or* ***Facilities****) – The Customer owned generating equipment and all associated or ancillary equipment, including Interconnection Equipment, on the Customer's side of the Point of Common Coupling (Point of Interconnection).*

- ***Feeder Terminal*** *– Origin of the feeder. Encompasses the breaker, relaying, monitoring, and control, typically in the originating substation. Note that, where feeders are supplied by two substations, the feeder would have two feeder terminals.*

- ***Generating Facility*** *– The device(s) for the production and/or storage for later injection of electricity identified in the Interconnection Application. This shall include the Generating Facility and Microgrid's Interconnection Facilities, but not the EPS Operator's Interconnection Facilities.*

- ***Generator Owner*** *– The owner of the Generating Facility that is interconnected to the EPS.*

- ***Grid*** *– The interconnected arrangement of lines, transformers and generators that make up the EPS Electric Power System.*

- ***Interconnection or Interconnect/ed/ing–*** *The result of the process of adding DER to an Area EPS, whether directly or via intermediate Local EPS facilities. (Excerpted from IEEE Std 1547™-2018.)*

- ***Interconnection Agreement(s)*** *– The agreement provided in Attachment 8 of the Puerto Rico Energy Bureau's Generating Facility and Microgrid Interconnection Regulation.*

- ***Interconnection Application-*** *The Interconnection Customer's request to Interconnect a new Generating Facility or Microgrid, or to increase the Nameplate Rating of, or make a Material Modification to the operating characteristics of, an existing Generating Facility or Microgrid that is Interconnected with the Electric Power System.*

- ***Interconnection Equipment*** *- That equipment necessary to safely Interconnect the Facility to the EPS, including all relaying, interrupting devices, metering or communication equipment needed to protect the Facility and the EPS and to control and safely operate the Facility in parallel with the EPS.*

- ***Interconnection Request –*** *The application for the Interconnection of generation within Puerto Rico is administered by LUMA.*

- ***Interconnection Study** – A technical study or studies performed to identify actions required to allow Generating Facility or Microgrid to be Interconnected to the grid. These studies are prepared in response to the Interconnection Application. Interconnection Studies may include, but are not limited to, service studies, coordination studies and facility impact studies.*

- ***Interconnection (or Interface (Isolation)) Transformer** - The transformer through which the Generating Facility Interconnects with the EPS. This may also be the electrical transformer that supplies energy to the Host Load.*

- ***Interoperability –** The capability of two or more networks, systems, devices, applications, or components to externally exchange and readily use information securely and effectively. (Excerpted from IEEE Std 2030™)*

- ***Interval Metering** – The metering equipment that measures consumed and exported energy, in quantities such as kWh and kVARh, in defined intervals.*

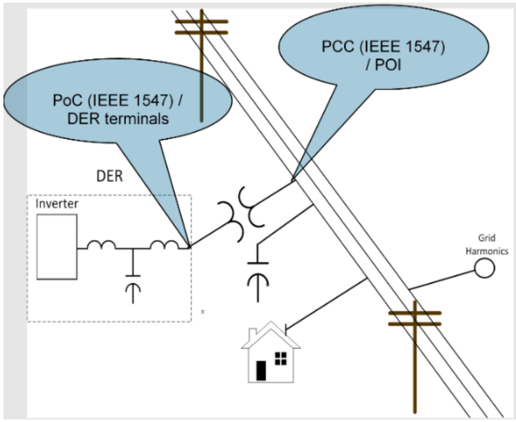
- ***Microgrid** – means a group of Interconnected loads and Generating Facilities within clearly defined electrical boundaries that acts as a single controllable entity that can connect and disconnect from the Electric Power System to enable it to operate in either Parallel (grid-connected) or Islanded (off-the-grid) mode. This shall include the Interconnection Customer's Interconnection Facilities. In some cases, the EPS Operator's Interconnection Facilities may also be included in the Microgrid.*

- *"**Meter**" or "**Metering**" – means the equipment or instruments which function is to measure and register the bi-directional flow of electric energy (i.e., energy delivered and received) by a Generating Facility or Microgrid Interconnected to the EPS.*

- ***NEM** – **N**et **E**nergy **M**etering or Net Metering Program - The Basic Net Metering Program established in Act 114-2007; the Aggregate Net Metering Program established by the Energy Bureau's Amended Order CEPR-MI-2014-0001; and the Shared Net Metering Program established by the Energy Bureau's Amended Order CEPR-MI-2014-0001.*

- ***Parallel Operation or Operation/Operate/Operating in Parallel** – The simultaneous operation of the Generating Facility or Microgrid such that power can be transferred across the Point of Common Coupling from or to the Electric Power System. This is also referred to as operating in "grid connected" mode, operating in parallel, or paralleling.*

- ***Power Delivery System (LUMA) –** See EPS definition. **Point of Common Coupling (PCC**) – The point where EPS service connects with the Generating Facility or Microgrid. This is usually the Point of Interconnection (POI). (Adapted from IEEE Std 1547™-2018.)*



- ***Point of Connection (PoC)*** *– The point where the DER is connected to the plant electric power system. (Excerpted from IEEE Std 1547™-2018.)*

- ***Point of Interconnection (POI)*** *– Point where the Customer system Interconnects with the utility grid. It is the demarcation point between Customer owned equipment and utility owned equipment. Typically, the same as the PCC.*

- ***Pre-application Study–*** *A Pre-Application study is a low-cost method of providing technical information about a specific Point of Interconnection, enabling a developer to assess the limitations and potential upgrades needed to Interconnect their proposed project.*

- ***RTU*** *(**R**emote **T**erminal **U**nit) – The remote unit of a supervisory control system used to telemeter operating data, provide device status/alarms and to provide remote control of equipment at a substation or generator site. The unit communicates with a master unit at the Control Center.*

- ***Reference Point of Applicability (RPA)*** *– The reference point of applicability for any requirement varies and can be at the Point of Connection (PoC) or Point of Common Coupling (PCC), or either. DER Requirements of this document apply to the RPA. (Excerpted from IEEE Std 1547™-2018; the location concept is defined in Clause 4.2.)*

- ***Stabilized*** *– The state of the Company's system when the voltage and frequency have returned to their normal range for at least 5 minutes following a disturbance. If tripped, Customer owned generation may reconnect to the EPS. The Company may require a longer time upon a reasonable showing that reconnection after only 5 minutes will adversely impact the safety and reliability of the EPS.*

- ***Stiffness Ratio*** *– A measure of how strong a generator's fault current contribution is in comparison to the total fault current available at the Point of Common Coupling. Stiffness Ratio = Total Fault Current Available at PCC (MVA)/Generator Fault Contribution (MVA).*

- ***System Emergency*** *-- An imminent or occurring condition on the EPS, or in the Facility that is likely to impair system reliability, quality of service, or result in significant disruption of service, or damage, to any of the foregoing, or is likely to endanger life, property or the environment.*

- ***Telemetry*** *– The process of recording and transmitting the readings of an instrument. For example, collection of measurements or other data at remote or inaccessible points and their automatic transmission to receiving equipment for monitoring. In the case of DERs, applications include telemetry for protection device status, for power flows, and for other plant or related utility equipment condition status.*

- ***Transmission System*** *- The facilities used to provide sub transmission (38kV) and transmission (115kV) service. This part of the EPS system is mostly meshed.*

2.2 Acronyms

ACR – Automatic Circuit Recloser

DA – Distribution Automation

DER – Distributed Energy Resource

EMI – Electromagnetic Interference

EPS – Electric Power System

ESS – Energy Storage System

IC – Interconnecting Customer

LVAC – Low Voltage AC

PoC – Point of Connection

PCC – Point of Common Coupling

POI – Point of Interconnection

PREB- Puerto Rico Energy Bureau

RPA – Reference Point of Applicability

TIR – Technical Interconnection Requirements

3. General Review Requirements

3.1 Criteria for DER Interconnection

All DER Interconnections will be evaluated for the following:

- Safety of the public and EPS Operator personnel
- Risk of degradation to services for Customers due to interruptions or power quality events
- Compromise of security or reliability of EPS electrical systems
- Applicability of DER size or primary source to the Energy Bureau's Generating Facility and Microgrid Interconnection Regulation.
- Help reaching Puerto Rico's tiered renewable energy goals

All developers and owners of approved DER Interconnections are required to be responsive to LUMA's direction and instructions during emergency conditions or to remove the DER from service when LUMA is performing line maintenance or other work on the circuit to which the DER is connected.

3.2 Application Technical Review Process

Guidelines for processing applications to Interconnect DER and the related technical reviews are specified by PREB's Generating Facility and Microgrid Interconnection Regulation. Details of the process depend on the complexity of the DER to be connected. PREB's Generating Facility and Microgrid Interconnection Regulation provides different DER application levels, which are defined by size, point of connection, DER type, and operating characteristics. The PREB specified levels define procedures and considerations of the technical review process. All connections to be Operated in Parallel with the electric grid are subject to technical review. Links to Interconnection Application processing are as follows:

- New PREB regulations
- TIR Summary
- Application portal
- Hosting Capacity Map

Technical review of each Interconnection Application shall be made to ensure that operation of the proposed DER system is consistent with the technical requirements of the power delivery system and does not adversely impact other customers. Existing LUMA technical guidelines for interconnecting generation to the grid include but are not limited to: LUMA Technical Interconnection Requirements Document, applicable PREB Rules, technical Interconnection standards and local codes.

The general principles of these Technical Interconnection Requirements, as considered in this document, are:

- DER Interconnection and operation shall not compromise the safety of the public or EPS Operator personnel.

- DER Interconnection shall not degrade service to any customers by causing interruptions or power quality events.
- DER Interconnection shall not compromise the security or reliability of EPS electrical systems and shall be responsive to LUMA's direction during defined emergency conditions or to requests to remove the DER from service when LUMA is performing work on the circuit to which the DER is connected.
- Cost of the DER Interconnections shall be clearly defined and borne by the owner/operator/installer as mandated by applicable tariffs or rules. DER Interconnection should not increase customer rates.
- The costs and benefits of the Interconnection of a DER should be assessed in light of the help said Interconnection provides to reaching the renewable energy goals set by law.

4. DER Technologies

This Section in conjunction with Section 14 cover the entirety of the resources that can interconnect to Puerto Rico's T&D grid. All equipment that forms part of a Generating Facility system based on renewable energy sources must be approved by the Public Energy Policy Program ("PEPP"), of the Department of Economic Development and Commerce ("DEDC") including, but not limited to, photovoltaic modules, wind turbines, synchronous generators, induction generators, inverters and control systems. More information on certification of equipment can be found in the Generating Facility and Microgrid Interconnection Regulation.

4.1 Inverters

Based on applicable rules and transmission and distribution system characteristics, inverter-based generators shall utilize equipment with advanced functionality, otherwise known as "smart inverters." Smart inverters typically have the following functionalities and capabilities:

- Frequency and voltage-disturbance ride through
- Ramp rate control
- SCADA communications
- Curtailment or other mitigation ability if high voltage were to occur
- Ability to receive and respond to a trip signal
- Ability to adjust PF or VARs based on EPS signal
- Ability to adjust Real Power Output based on EPS signal
- Ability to set and adjust Volt/VAR and Volt/Watt curves to provide grid support or avoid grid violations
- Anti-Islanding capability

Inverters shall be UL 1741 certified as "Grid Support Interactive Inverter" or "Grid Support Utility Interactive Inverter" installed or commissioned with the IEEE Std 1547™-2018 specified performance capabilities. Unless specified otherwise, all grid support functions shall be initially disabled.

These requirements and functionalities are already specified in IEEE Std 1547™-2018 for all future DERs and shall be required when product is available and as specified by PREB or tariff.

Specific settings within the plant capability may be required at the time of installation or later if conditions change. Within the conditions of the Interconnection Agreement, LUMA may need to control the DER through communication devices. This includes communication interoperability that may be used to update specific functions and settings.

Other inverter requirements include:

- To address steady state high voltage on the circuit due to output from a DER, LUMA may require the DER to reduce power output when grid voltage goes above ANSI limits.
- Where an ACR has been installed, LUMA may monitor voltage at the ACR and disconnect the DER facility by opening the ACR, for high voltage.

- DERs utilizing inverters may wish to consider oversizing the inverters slightly to reduce impact on real power output if/when they export or import VARs to maintain proper voltage.

Facilities required to implement Dynamic VAR compensation, shall have the capability of dynamically compensating for power fluctuations to mitigate the change in voltage at the Point of Common Coupling (PCC). Voltage changes due to power output fluctuations shall be kept in compliance with IEEE Std 1547™-2018 requirements. The systems must be able to perform dynamic control in addition to steady state voltage control described above.

LUMA allows the use of equipment with inverter technology, generators, relays and other devices that comply with applicable standards and codes. These have to be evaluated and approved by LUMA. LUMA has a list of approved inverters and control systems periodically updated, which is made available on the DG Portal website. If the equipment has not been evaluated and approved by LUMA, it may request that the manufacturer, distributor or owner send to LUMA, in digital file in PDF format, documents certifying that the inverter complies with the following:

1. Are certified by a Nationally Recognized Testing Laboratory. This ensures that they meet the acceptance criteria of the tests required in the IEEE 1547-2018 or UL 1741 standard and its Supplements, as applicable, for equipment that continuously Operates in Parallel with the systems of the electricity companies.
2. Comply with the permitted harmonic content distortion limits, according to the IEEE 1547-2018 standard and other applicable ones.
3. Comply with the Voltage Flicker limits, depending on the IEEE 1547-2018 standard and other applicable.
4. Comply with applicable regulations. Should any conflict arise with other standards, the applicable regulations will prevail.
5. Have the ability to Operate in Parallel with the EPS.
6. Have the ability to adjust in the field of frequency, voltage and operating times.

4.1.1 Renewable resources

All equipment that forms part of a Generating Facility system based on renewable energy sources must be approved by the Public Energy Policy Program ("PEPP"), of the Department of Economic Development and Commerce ("DEDC") including, but not limited to, photovoltaic modules, wind turbines, synchronous generators, induction generators, inverters and control systems. PEPP must certify that the inverters and control systems that interconnect the renewable energy sources with the electrical network comply with the applicable standards. The list of equipment and components certified by the PEPP is available on the Energy Bureau's website (http://energia.pr.gov).

4.2 Synchronous Generators

For Synchronous Generators, the generator may be required to operate in a mode that mitigates high voltage during low load periods such as operating the generator under excited and thus absorbing VARs to limit the local high voltage.

Protection schemes must be designed to ensure detection of fault conditions on the EPS.

4.3 Battery Storage

Evaluation of DER Battery Energy Storage Systems (ESS) will be based on the application, feeder operation and the customer planned ESS operating mode. Interconnection considerations will include reverse power under maximum discharge (exporting) at minimum load and the maximum charging power (importing) at the maximum load condition. If used in conjunction with other generation, the impact of running both at the same time must be studied.

ESS systems have several different potential operating modes. Modes that export power include local grid support (including frequency regulation). Non-exporting modes include self-consumption of other generation such as solar PV, backup power, and load shifting/demand management.

Systems intended to operate in a frequency regulation mode may have additional requirements because of rapid change from charge to discharge with potential to cause voltage regulation issues. When evaluating ESS that are responding to a frequency regulation signal, it is assumed they act in unison and the aggregate capacity will be used to assess the maximum impact on the circuit. Voltage rise/drop, and fluctuation are limited based on the circuit, DER location and related standards including IEEE Std 1547™-2018.

For behind-the-meter applications where the ESS never exports while Operating in Parallel with the grid and both the ESS and the solar system share one inverter, no additional metering or monitoring equipment shall be required for a solar-plus-storage facility than would be required for a solar facility without storage technology.

4.4 Induction Generators

Customers shall be required to install mitigating equipment in cases where induction generators for intermittent sources cause voltage or reactive current issues. Customer or EPS power factor correction capacitors near an induction generator site can increase the probability of self-excitation of the generator when isolated from the grid. This can result in an inadvertent island that may pose a risk to personnel and result in abnormally high voltages, requiring protection elements to mitigate said issues.

5. General Technical Requirements

These requirements are applicable at the Reference Point of Applicability. This can be either the PCC or PoC, or both, depending on several parameters including DER size, percent of local load demand, and related protection coordination. Requirements that depend on external exchange of inputs such as between two or more networks, systems, devices, applications, or components need to be interoperable, able to exchange and readily use information securely and effectively.

In what follows heretofore, we analyze various specific technical requirements per area. Several of them are related to IEEE 1547-2018. The table below shows topics mentioned in this document, the relevant section of the IEEE standard, as well as the applicability to the EPS process/system.

Table 5-1. IEEE 1547 clauses used in the TIR document

Section title	IEEE 1547-2018 clause	Applicability
Applicable Voltages	4.3	In addition to 116.4V self-imposed primary voltage limit
Effective Grounding	4.12	Always
Cease to Energize	4.5	Always
Control Capability Requirements	4.6	Always
Priotization of DER Responses	4.7	Always
Isolation Device	4.8	Systems >300kVA
Inavertent Energization of Area EPS	4.9	Always
Enter Service	4.10	DER <250kVA
DER interconnection integrity	4.11	Always
Reactive power capability	5.1, 5.2	Inverter-connected are Category B, synchronous generators are Category A
Reactive power control	5.3	Always
Active Power Control	5.4	Inverter-connected (Category B)
Open-phase conditions	6.2	Always
Area EPS faults	6.2	Always
Area EPS reclosing condition	6.3	Always
Frequency trip and ride-through requirements	6.5	Default settings
Unintended islanding detection	8.1	DER >25kW
Limits on DER DC injection	7.1	Always
Limits on DER-caused voltage fluctuations	7.2	Always
Limits on harmonic distortion	7.3	In addition to 5% around the 60Hz frequency
Limits on transient overvoltage from DER	7.4	Always
Plant interoperability	10	Always
Plant commissioning tests	11	Always

5.1 Applicable Voltages

The applicable voltages determine the performance of a Local EPS or DER and are the electrical quantities specified about the reference point of applicability, individual phase-to-neutral, phase-to-ground, or phase-to-phase combination and time resolution.

5.1.1 Medium-Voltage Connections:

For DER with a PCC located at the medium-voltage level, the applicable voltages shall be determined by the configuration and nominal voltage of the Area EPS at the PCC.

5.1.2 Low-Voltage Connections:

For DERs with a PCC located at the low-voltage level, the applicable voltages shall be determined by the configuration of the low-voltage winding of the power transformer(s) between the medium-voltage system and the low-voltage system. The applicable voltages that shall be detected are shown in Table 5-2 and Table 5-3. For multi-phase systems, the requirements for applicable voltages shall apply to all phases.

Table 5-2. Applicable voltages when PCC is located at medium voltage

DER Connection at PCC	Applicable voltages
Three-Phase, Four-Wire	Phase-to-phase and phase-to-neutral
Grounded Three-Phase, Three-Wire	Phase-to-phase and phase-to-ground
Ungrounded Three-Phase, Three-Wire	Phase-to-phase
Single-Phase, Two-Wire	Phase-to-2nd wire (the 2nd wire may be either a neutral or a 2nd phase)

Table 5-3. Applicable voltages when PCC is located at low voltage

Low-voltage winding configuration of Area EPS transformer(s)[a]	Applicable voltages
Grounded Wye, or Zig-Zag[b]	Phase-to-phase and phase-to-neutral, or Phase-to-phase and phase-to-ground
Ungrounded Wye, or Zig-Zag	Phase-to-phase or phase-to-neutral
Delta[c]	Phase-to-phase
Single-Phase 120/240 V (split-phase)	Line-to-neutral—for 120 V DER units Line-to-line—for 240 V DER units[d]

[a] A three-phase transformer or a bank of single-phase transformers may be used for three-phase systems.

[b] For 120/208 V two-phase services, line-to-line voltages shall be sufficient.

[c] Including delta with mid tap connection (grounded or ungrounded).

[d] Sensing line-to-neutral on both legs of a 120/240 V split-phase or Edison connection effectively senses the line-to-line and is therefore compliant with this requirement. Sensing line-to-ground may also be used; however, the ground connection should only be used for voltage sensing purposes.

The DER shall not cause the delivery voltage levels on the LUMA system to deviate outside of the range of voltages described by ANSI C84.1, Electric Power Systems and Equipment, or in the applicable PREB regulation, if it is different than ANSI.

DER Interconnections may require a 3-phase connection depending on size. If three-phase service is available, it is preferred for most systems larger than 25 kW and is required for any system 100 kW or greater. All 3 phase systems shall operate with balanced output on each phase under normal operating conditions.

The target steady state delivery voltages for EPS (on a 120 V base) are:

EPS	Highest Voltage	Lowest Voltage		Notes
		Primary	Meter	
LUMA	126 V	116.4V[2]	114 V	

.

[2] This is a self-imposed limit. Additional requirements for applicable voltages are specified in IEEE Std 1547™-2018 clause 4.3 - Applicable Voltages. These requirements include phase-to-phase, phase-neutral and phase-to-ground configurations, the standard also identifies requirements where the DER does not measure individual phase voltages and requirements for determining applicable voltages for low and high voltage ride-through.

5.2 Existing Service Transformer Connections

Low voltage DER connections are normally via an existing EPS load service transformer. Larger plants may require either an upgrade of the service transformer or the addition of a DER plant service transformer.

5.2.1 Distribution Service Transformer Capacity

There are size limits for the transformer relative to the DER. The following size considerations shall apply to determine when a DER Interconnection Application requires a service transformer upgrade:

- If the aggregate DER output is greater than the transformer nameplate rating, it shall be replaced.

$$\sum_{b} DER_b \geq S_N$$

- If the existing service is open wye-open delta banks and the DER is three-phase. And if single phase DER exceeds 20% of the capacity of the transformer or is expected to create an unbalance in current of more than 20%.
- When voltage-rise associated with DER power back feed is anticipated the service transformer may need to be upgraded to maintain voltage with standard limits.

5.2.2 Replacement Transformer Configuration Requirement

The following winding configuration requirements shall apply where a DER Interconnection Application requires a transformer replacement or an additional transformer:

Acceptable	Grounded Wye / Grounded Wye[1]
	Grounded Wye / Delta[1]
Conditionally Acceptable	Delta / Delta[2]
	Delta / Wye[2]
	Delta / Grounded Wye[2]
	Grounded Wye / Wye[2]

[1] This transformer option may impact the MV protection coordination and require review and potential modifications to settings.

[2] Acceptable with three phase overvoltage protection that coordinates with utility equipment Temporary Overvoltage withstand

- Three-phase DER systems shall not be connected to Open Wye-Open Delta banks. Single phase DER systems must only be connected to Open Wye-Open Delta banks if they are connected to the larger transformer (lighting) and are less than 20% of the capacity of that transformer and create less than 20% unbalance.
- In areas where a voltage level is being retired, the developer will be required to use a dual voltage transformer and associated equipment rated to operate at the higher voltage

level, so that when a conversion takes place, the transformer will support the new voltage level.

- For large projects connecting to the primary, especially on an express circuit, the developer shall be advised to use a transformer with no load taps (+/- 2.5 and 5% typically).

5.2.3 Basic Insulation Levels (BIL)

Rating of any new transformer must coordinate with the requirements of the EPS at the PCC. All customer equipment should be designed to the BIL rating of the EPS line to which it is being interconnected.

5.3 Effective Grounding

The DER Interconnection (inclusive of DER assets and interconnecting transformer) must be compatible with the feeder grounding practice at the Point of Interconnection. With some exceptions, installations should meet the requirements for "effectively grounded" as described in IEEE/ANSI C62.92.2 for synchronous machines and C62.92.6 for inverters. Effective grounding is also a requirement specified in IEEE Std 1547™-2018 clause 4.12 - Integration with Area EPS Grounding.

- In the case of synchronous machine generation, the following inequalities serve as a rule of thumb to determine a system is effectively grounded:

$$X0/X1 < 3 \text{ and } R0/X1 < 1$$

- In case of inverter DER where $Z1 \neq Z2$, the grounding requirements shall be such that the ground fault overvoltages will not exceed the limits contained within 1547-2018. LUMA may require proof of meeting this requirement, in the form of an Electromagnetic Transient study to be conducted by the proponent.

5.4 Open-phase Detection

The DER shall detect and cease to energize and trip all phases to which the DER is connected for any open phase condition occurring directly at the reference point of applicability and the applicable voltages per 5.1 above. The DER shall cease to energize and trip within 2.0 seconds of the open phase condition.

The design and implementation of the Interconnection shall eliminate the potential for ferro-resonance. Voltage protection is required on the secondary and may also be required on the primary side.

5.5 Cease to Energize

DER cease to energize performance requirements are specified in IEEE Std 1547™-2018 clause 4.5. Cease to energize is identified as “cessation of active power delivery.” This still allows for limited reactive power from passive devices. This function is specified in several DER response requirements.

5.6 Control Capability Requirements

The DER shall respond to external inputs that include tripping the unit, limiting active power, and executing mode or parameter changes. Any control capability will require telemetry. These capabilities need to be interoperable to exchange status and readily follow the external input.

Requirements are specified in IEEE Std 1547™-2018 clause 4.6. Limiting DER active power is normally to a maximum agreed set point, or in the case of DER combined with load, it may be the net export power including load variations. This normally allows up to 30 seconds of limited, inadvertent export that does not cause operating violations.

5.7 Prioritization of DER Responses

The priority or precedence of different DER response requirements to varying conditions are laid out in IEEE Std 1547™-2018 clause 4.7. These include disabling permit service, trip, ride-through, voltage-active power mode, active power limit and voltage regulation modes.

5.8 Isolation Device

Customers are required to install an approved device for all Interconnections for isolating the DER from the EPS. The device shall be readily accessible, have a visible-break, physical disconnect capable of interrupting full load current and be lockable in an open position. These requirements incorporate requirements in IEEE Std 1547™-2018 clause 4.8 - Isolation Device.

LUMA requires the installation of a disconnect switch as defined above for all systems above 300kW. An ACR shall be required for DER sizes over 300kW. In that case, an acceptable disconnect that LUMA can access will be required. If remote trip or direct transfer trip are required, the isolating device shall be able to operate based on the respective signal.

5.9 Inadvertent Energization of Area EPS

IEEE Std 1547™-2018 clause 4.9 - Inadvertent Energization of the Area EPS requires that the "DER shall not energize the Area EPS when the Area EPS is de-energized."

5.10 Enter Service

For DERs ≥250 kVA, ramp up of power output shall be limited so the voltage at the Point of Common Coupling will comply with the voltage requirements and to ensure existing regulation equipment can properly adjust. Ramp up should be 2 MW per minute or less on 12 – 13.8 kV circuits, 3 MW per minute or less on 23 - 25 kV circuits, and 5 MW per minute or less on 34 kV circuits. The energization of step-up transformers must be limited to the ramp rate schedule.

For DERs <250 kVA requirements are specified in IEEE Std 1547™-2018 clause 4.10 - Enter Service. These include the allowable voltage and frequency ranges for entering service and performance during entering service. Settings include a delay to enter service of 300 seconds and a duration for entering service of 300 seconds applying a linear or stepwise linear ramp.

5.10.1 Synchronization

Requirements for synchronization are specified in IEEE Std 1547™-2018 clause 4.10.4 - Synchronization. These requirements provide maximum voltage step changes when synchronizing and synchronization parameter limits for different DER kVA.

5.11 DER Interconnection integrity

This Section addresses immunity requirements of the DER to operate properly and safely in typical and expected grid environments. These DER certification requirements intend to promote electromagnetic compatibility of the DER with the electric grid and are covered in IEEE Std 1547™-2018 section 4.11.

5.11.1 Electromagnetic Interference

IEEE Std 1547™-2018 clause 4.11.1 - Protection from Electromagnetic Interference (EMI) identifies the DER immunity requirements for DER performance-critical controls and protections.

5.11.2 Surge Withstand

Voltage and current surge withstand requirements for the DER are specified in IEEE Std 1547™-2018 clause 4.11.2 - Surge Withstand Performance.

5.11.3 Paralleling device

Requirements for the paralleling device, including the requirement to withstand "220% of the DER rated voltage across the DER paralleling device," is specified in IEEE Std 1547™-2018 clause 4.11.3 - Paralleling Device.

6. DER Support of Grid Voltage

6.1 Reactive Power Capability

All DER installations will be required to have reactive power support capability. This means the individual DERs, or the DER systems (at PCC or plant level), shall be capable of injecting reactive power (over-excited) and absorbing reactive power (under excited). As specified in IEEE Std 1547™-2018, there are category A and B capability requirements as shown in Table 6-1.

Table 6-1. Applicable Minimum reactive power injection and absorption capability

Category	Injection capability as % of rated apparent power (kVA)	Absorption capability as % of rated apparent power (kVA)
A (at DER rated voltage)	44	25
B (over the full extent of ANSI C84.1 range A)	44	44

For both categories A and B, the full kVAR minimum capability is required for active power output levels above 20% of rated power. For reduced real power output levels, from 5% to 20%, the DER % reactive power requirement is calculated by % active power/20% rated active power.

6.2 LUMA Requirements

- Inverter-connected DERs shall have Category B reactive power capability and will be set according to EPS requirements. Depending on PCC, DERs >250 kVA will be reviewed to determine final control mode and settings.
- Synchronous machine connected DERs shall have the Category A reactive power capability and will be reviewed for the final control mode and settings. Note, synchronous DERs may be required to mitigate high voltage by absorbing reactive power during low load periods.
- Induction-connected DERs do not have a predetermined reactive power requirement. Technical review will determine if supplemental reactive compensation is required.

Based on technical review, a DER facility of any size of technology may be required to operate in one of several reactive power control modes as described in Section 6. These are normally identified during technical review and confirmed at commissioning. The facility may be asked to operate in a different control mode or setting in the future if LUMA determines that it is necessary to regulate voltage in the area.

As specified in IEEE Std 1547™-2018 clauses 5.1 and 5.2 – DER Reactive Power Capability further defines requirements for Category A and Category B generation. All DERs certified to the standard are expected to meet at least Category B requirements.

6.3 Reactive Power Control

The DER shall be capable to provide voltage regulation by changes of reactive power. LUMA will specify reactive power control requirements and settings when needed to actively support voltage regulation. Required modes of voltage regulation using reactive power control include:

- Constant power factor
- Voltage-reactive power Volt/VAR
- Constant reactive power mode

A further description of reactive power control mode requirements for DERs is specified in IEEE Std 1547™-2018 clause 5.3 - Voltage and Reactive Power Control. The standard identifies required voltage and reactive power support requirements. LUMA will provide the proper settings.

6.4 Active Power Control

The DER may be required to provide voltage regulation capability by changes of active power. Modes of voltage regulation using active power control include Volt/Watt and Active power-reactive power mode.

Active power control requirements are specified in IEEE Std 1547™-2018 clause 5.4 - Voltage and Active Power Control. The standard identifies required voltage-active power control function requirements and setting requirements for Category B generation. Table 10 in this clause identifies Voltage-active power settings. LUMA will provide the proper settings.

7. DER Response to Abnormal Conditions

Events on the grid such as an open phase or system fault, and the related actions by LUMA to clear problems or to restore service are not uncommon. This Section covers the expected DER response to these conditions. Typically, a different response is expected depending if the event directly affects the DER such as a fault and on the same feeder or if indirectly affecting, such as a low voltage or frequency event from a different part of the grid.

7.1 Area EPS Faults

DER protective devices shall be rated to safely interrupt fault current levels at the location. Available fault current levels depend on the point of connection. The requirement will include the aggregate fault current expected from all sources, the range of fault current scenarios and for all expected feeder operating alternatives.

Requirements for area EPS faults including cease to energize and trip requirements is specified in IEEE Std 1547™-2018 clause 6.2.1 -Area EPS Faults.

7.2 Open-Phase Conditions

Requirements for open-phase include cease to energize and trip within 2 seconds of an open-phase condition and are specified in IEEE Std 1547™-2018 clause 6.2.2. The DER facility must be able to sense open-phase conditions at the reference point of applicability. Note Clause 4.1 (Reference Point of Applicability) in the standard allows for the RPA to be moved to the high-voltage side DER transformers that may otherwise break the zero-sequence continuity.

7.3 Area EPS Reclosing Coordination

LUMA’s automatic reclosing practices for overhead circuits are aimed to maximize the reliability of service to other customers. Interconnecting DERs should not require modifying standard auto-reclose schemes at transmission substations, distribution centers, or other sectionalizing devices. The IC is responsible for protecting the DER facility's equipment so that automatic or manual reclosing, faults, or other common grid disturbances do not cause damage to the equipment.

When automatic reclosing may result in equipment damage or a safety hazard, either to the EPS or customer facilities, LUMA will require additional protective equipment be installed. For example, some DER configurations may require direct transfer trip of connected DERs for line faults. This will usually consist of communication and/or control equipment to disconnect the customer owned DER (or to confirm that it is disconnected) before the EPS supply line is reclosed.

IEEE Std 1547™-2018 clause 6.3 - Area EPS Reclosing Coordination identifies requirements for Area EPS reclosing. These include requirements for coordination with LUMA’s reclosing scheme, consideration when entering service, and voltage ride-through requirements for consecutive temporary voltage disturbances caused by reclosing sequence.

7.4 Voltage Trip and Ride-through Requirements

Manufacturer specifications for all voltage protection schemes must be submitted to LUMA for review if other than default settings for ride-through Category III of IEEE Std 1547™-2018 are used.

If this protection is not an integral part of a tested, certified, and listed power system Interconnection system, LUMA shall have the right to require testing of the protection system at the customer's expense.

All synchronous machine DERs shall provide Category I capabilities and all inverter-based DERs shall provide Category III capabilities. Any instances that do not fall within the above capabilities shall be reviewed on a case-by-case basis and with the Area EPS Operator making determination[1] for requiring Category I, II or III.

7.5 Frequency trip and ride-through requirements

Frequency trip settings and ride-through capability requirements for abnormal conditions are specified in IEEE Std 1547™-2018, clause 6.5, and are the same for Category I, II, and III. LUMA requires the default settings specified in the standard for both ride-through capability and trip settings.

Manufacturer specifications for any frequency protection schemes must be submitted to LUMA for review if any settings are changed or if non-standard settings for ride-through Category II are used. If this protection is not an integral part of a listed, manufactured power source Interconnection system, LUMA shall have the right to require testing of the protection device systems at the customer's expense.

Rate of Change of Frequency (ROCOF) ride-through requirements, and voltage phase angle changes ride-through requirements shall also apply. All synchronous machine DERs shall be assigned to provide Category I voltage phase angle capabilities and all inverter based DERs shall be assigned to provide Category III voltage phase angle capabilities. Any instances that do not fall within the above assignment shall be reviewed on a case-by-case basis, with the Area EPS Operator making determination for requiring Category I, II or III voltage phase angle capabilities.

For frequency-droop requirements, all synchronous machine DERs shall be assigned to provide Category I capabilities and all inverter-based DERs shall be assigned to provide Category III capabilities. Any instances that do not fall within the above assignment shall be reviewed on a case-by-case basis, with the Area EPS Operator making determination for requiring Category I, II or III frequency-droop capabilities. Frequency-droop default settings shall be used.

For Category II and III, DER frequency droop response is required during low frequency operation and shall be subject to the available active power and any headroom available. Response to high frequency conditions shall be mandatory for all DERs.

[1] LUMA will consider Annex B of IEEE 1547™-2018 when making these determinations on a case-by-case basis.

8. Protection Coordination Requirements

LUMA will determine the bus and line configurations and the protection requirements that are necessary to connect the DER proposed in the IC's application. This Section provides protection guidelines and requirements of the most commonly used configurations for Parallel Operation. Protection requirements for a specific plant may be greater than those listed, based on existing system conditions (e.g., other existing or previously queued DERs on the same circuit), and are considered on a case-by-case basis.

In the case of DER plants, such as PV with multiple inverters or other certified equipment, additional equipment is often required to provide adequate protection of the T&D system. Requirements for additional protective equipment due to Parallel Operation of DERs will vary depending on the capacity (MW) of the DER facility and on the configuration of the EPS.

Typical protection requirements for all sites are covered in this Section. Additional specific protection requirements for radial feeders are provided in Section 9. Requirements for network connected DERs are in Section 11. Examples of relay and relay functional requirements for different types and sizes of DER plants are listed in Appendix D. Finally, general protection schemes are further described in Appendix E that provide basic information on the types of protection schemes necessary for generator Parallel Operation.

8.1 Buffer Zone Capacity

Buffer zones are set around specific DER integration requirements such as current levels, individual or aggregate DER capacity, and reverse power kVA limits. Buffer zones indicate nearing, or exceeding, a limit and provide a margin of safety. They indicate when mitigation alternatives need to be considered for Interconnection, for example, at a substation, feeder, or PCC hosting capacity limit.

8.2 Unintended Islanding Detection

Anti-islanding capabilities are required for all DERs and for all installations. The anti-islanding protection shall trip the DER within 2 seconds of the formation of an island (loss of grid power). Trip time for DERs on feeders protected with automatic reclosers will need to be coordinated with the reclosing systems. This may require additional equipment such as transfer trip or suitable alternative.

LUMA will require the developer to identify and disclose the method of islanding detection that is being used for all DERs above 25 kW. LUMA reserves the right to require a customer to disconnect the DER at any time when necessary to protect the grid and/or other customers. Additional requirements for anti-islanding protection are specified in IEEE Std 1547™-2018 clause 8.1 - Unintentional Islanding.

8.3 Transfer Trip Protection

Often referred to as Direct Transfer Trip (DTT), this protection is used for most synchronous generators and for larger inverter connected DER installations. It may be required for smaller DER applications when the feeder hosting capacity exceeds buffer zone limits by DER connections. The objective of DTT is to quickly and reliably remove feeder distributed generation when grid power is interrupted. A secondary objective for DTT is to clearly distinguish events where the DER should not trip.

In most cases a fiber-optic cable or another acceptable communications medium is required to coordinate with the protection scheme of the distribution system. This requirement depends on DER type, unintended island detection and/or DER penetration levels relative to the feeder capacity. Criteria currently being applied where transfer trip is required include:

- Any inverter-connected systems greater than 750 kW or where the installed DER capacity has or is anticipated to exceed the safety buffer where reverse power on any LUMA equipment serving the plant.
- Any synchronous connected (rotating machine) generator greater than 250 kW, or if the nameplate rating is greater than 1/3 of the net minimum load in each upstream protective zone.
- LUMA will consider all existing generation with and without DTT in the same zone of protection in the determination of a DTT requirement.

8.4 Overcurrent Protection

The DER shall not generate current flow more than the component rating for EPS equipment. This is inclusive of allowable, emergency, and fault duty system ratings.

Overcurrent protection and ground fault overcurrent protection is required to be coordinated with upstream protection devices and should be set to be capable of sensing faults on the interconnected feeder.

For synchronous generators, a directional overcurrent element may be required.

8.5 Short Circuit Current Interrupting Capacity

When adding DERs, the short circuit current levels (in aggregate from all sources) resulting from the addition of the DER shall not exceed 85% of the interrupting rating of any impacted EPS or customer-owned protective devices and equipment.

The DER (in aggregate from all sources) shall not contribute more than 10% of the distribution system's maximum available fault current at the primary voltage point of common coupling (PCC). If this limit is exceeded additional engineering review may be required.

The DER customer may be required to redesign their facility to reduce fault contributions. These redesigns include, but are not limited to:

- Installing a generator with adequately large sub transient reactance
- Installing a transformer with sufficiently high impedance
- Installing a current-limiting reactor

8.6 Protective Relays (or built-in protection functions)

Interconnection configurations are site and feeder dependent. LUMA will determine the protection requirements that are necessary to connect the DER. The types of protection required depend on the DER and the site. Appendix B identifies common DER configurations by size, certification, and type of distribution circuit. Typical protective relay functional requirements are in Appendix D.

8.6.1 Review of Specifications

Manufacturer specifications for frequency and voltage protection schemes must be submitted to LUMA for review. If this protection is not an integral part of a listed, manufactured power source Interconnection system, LUMA shall have the right to require testing of the protection device systems at the customer's expense.

8.7 Telemetry

Telemetry shall be implemented for any DER larger than 2 MW AC as well as for any DER 250 kW AC or greater on a feeder that has or may have distribution automation. LUMA reserves the right to require telemetry as necessary for monitoring and control to maintain reliability. LUMA retains the discretion to determine when required for smaller DER Interconnections to install such equipment.

LUMA will specify all necessary protective relaying, communication, and SCADA requirements for DER Interconnection. Interconnection-specific details of telemetry requirements will be provided at the initial project meeting with LUMA. The IC will be responsible for the installation cost and ongoing communication costs of the DER plant required telemetry.

DER plant telemetry normally monitors 3-phase voltages, 3-phase amperages, total MW, total MVAR, MW-Hours, and MVAR-Hours and is required under the following circumstances for radial-connected DERs:

- Any plant 2 MW or greater.
- Any plant with required remote trip shall have continuous telemetry that monitors plant generation output.
- If the plant requires transfer trip communication for protection, then transfer trip communication status shall be telemetered.

Note that special telemetry requirements for Network Service can be found in Section 11 and any related interoperability requirements for telemetry are in Section 10. Meanwhile, Appendix G delineates telemetry options for plants ≥2 MW.

8.8 Remote Trip (via Cellular or Radio) Capability

An Automatic Circuit Recloser (ACR) may be required at the customer's expense for systems 1 MW and greater. This is not an alternative to any DTT protection requirements.

The ACR shall have appropriate relaying and remote-control capability. Depending on location and coordination with other feeder protection, the ACR monitors local voltage and plant current and may be programmed to trip for generator or feeder faults, for sustained voltage outside of predefined limits, and for outages.

NOTE: If the DER is behind the customer's meter, LUMA will work with the customer to establish a means of tripping the DER without loss of service to other loads.

8.9 Other Equipment and Protection Requirements

A DER may or may not be allowed to operate under alternate supply. This determination will be made by LUMA during the Interconnection assessment. If allowed to interconnect to the alternate supply, for customer locations where switchgear is equipped with alternate feeds, and employs automatic-transfer capability, protection shall be provided to block the transfer while DERs are paralleled to the system to prevent an out-of-phase condition. In addition, if required protection is not installed on the customer alternate source, the DER will be tripped before the customer is transferred to the alternative source.

9. Power Quality

DER Operating in Parallel with the grid should not degrade power quality to any other customers served by the electric grid. Several power quality standards have traditionally supported maintenance of voltage and power quality in the electric grid. 2 The latest IEEE Std 1547™-2018, Section 7, addresses the power quality requirements specifically for DERs Operating in Parallel with the grid. Note these are primarily emission limits for DERs in normal operation, and do not necessarily address inadvertent mis-operation or DER failure modes that may impact other customers on the grid.

Referring to the IEEE Std 1547™-2018 limits, LUMA require DERs to be certified to meet the standard and any other limits within his Technical Interconnection Requirements.

9.1 Limits on DER DC Injection

Direct current, or a DC-offset, from DERs is restricted because low-levels can saturate instrumentation and Interconnection transformers causing mis-operation of protective devices that can lead to power outage. Limits during normal operation are specified in IEEE Std 1547™-2018 clause 7.1 - Limitation of DC Injection.

9.2 Limits on DER-caused Voltage Fluctuations

Voltage fluctuation limits depend on both the DER relative size and the strength of the grid (stiffness ratio) at the PCC. The main concerns are DER-caused fluctuations on the medium voltage power system. LUMA requirements address a rapid voltage change (RVC) such as caused by switching large real or reactive power components, a repeating power fluctuation causing flicker, and power fluctuations that cause excessive voltage regulator operations. RVC and flicker limit are specified in IEEE Std 1547™-2018 clause 7.2 - Limitation of Voltage Fluctuations Induced by the DER.

Note, effective mitigation of DER-related voltage fluctuations is normally achieved by ensuring that the proposed grid connection point has sufficient capability relative to the DER plant rating. A stiffness ratio comparing the grid short circuit power to the DER plant power of 25 times is normally required.

9.2.1 Rapid Voltage Change Limits

In normal operation the DER shall not cause RVC changes that exceed ΔV of 3% at medium voltage and 5% if the PCC is at low voltage. Excluded are rare events such as transformer energization during a plant start-up or restoration.

9.2.2 Flicker Limits

In normal operation the DER shall not cause repetitive changes of power output leading to voltage fluctuations. To determine compliance an allocation of the grid's flicker capacity at the PCC is provided to the DER. The allocation is $P_{st} \leq .35$, based on a 10-minute evaluation of DER-caused

[2] Power system compatibility standards such as IEEE 519 (on harmonics), IEEE 1453 (on power fluctuations), and IEC 61000 series (on Electromagnetic Compatibility).

voltage fluctuations. Compliance can be estimated based on stiffness ratio and plant output variability or can be determined by a measurement using a typical power quality monitor.

9.2.3 Compatibility with Voltage Regulation Equipment

The DER shall not cause excessive operation of EPS owned voltage regulators, tap changers, and voltage or VAR-switched capacitors. Rapid changes, where the voltage recovers in less than 10 seconds, are excluded. The following change limits shall apply to minimize excessive voltage regulating equipment operations:

- Voltage Regulators – voltage changes are limited to ½ the bandwidth of any voltage regulator (line or substation) measured at the regulating device.
- Capacitors – voltage changes are limited to ½ the net dead bandwidth of any switched capacitor bank measured at the device.
- VAR Switched Capacitors – reactive power changes not to exceed ½ the bandwidth of any VAR switched capacitor bank measured at the device.

9.3 Limits on Harmonic Distortion from DER

The DER shall not introduce or promote unacceptable distortions in the grid voltage sine wave at the PCC. This limit is applied to DER current total rated-current distortion (“TRD”) and shall not exceed 5% of the fundamental 60 Hz frequency. Additional requirements for voltage and current distortion individual harmonics are those specified in IEEE Std 1547™-2018 clause 7.3 - Limitation of Current Distortion.

9.4 Limits on Transient Overvoltage from DER

DERs Operating in Parallel with the grid shall not, by their design or application, cause transient overvoltage that may exceed EPS or customer equipment tolerances. Events leading to overvoltage include interaction of the DER during ground faults, with grid switching transients, or from disconnection of the DER.

Specific limits are defined in IEEE Std 1547™-2018 clause 7.4 - Limitation of Overvoltage Contribution. If DER cause objectionable overvoltage, then mitigation is required at the DER owner’s expense.

Cumulative instantaneous overvoltage shall be limited to the requirement found in 1547-2018.

9.5 Maintaining Phase-Voltage Balance

All 3-phase DER installations shall maintain a balanced power output during normal operations. DER Interconnections may not create current unbalance that causes any phase voltage in service to other users to violate LUMA requirements for 3-phase balance. In most areas the objective is to limit 3-phase unbalance to 3%. This objective is also identified in the informative appendix of ANSI C84.1, 2016, and is defined as follows:

$$phase\ voltage\ unbalance\ (\%) = 100 \cdot \frac{\max deviation\ from\ average\ phase\ voltage}{average\ phase\ voltage}$$

There are three definitions of voltage unbalance. The first definition (IEEE 112), used in the equation above, is using phase measurements. The second definition (NEMA) uses line voltage. The third definition, often times called "true" definition, is defined as V2/V1. The first two definitions, if employed, will have a limit of 3%. The third definition, if employed, will have a limit of 2%. LUMA will use the most appropriate definition on a case-specific basis, depending on the assessment it is conducting. Unbalance is defined in terms of phase current. As an additional requirement, DERs should not cause current unbalance to exceed planning limits for feeders. This planning limit is a 15% difference in phase currents, calculated similarly as voltage unbalance. If the DER causes current unbalance exceeding this limit mitigation or upgrades may be required.

9.6 Grid Integration for Radial-Connected DER

9.6.1 General Requirements

Integration requirements for radial-connected DERs address compatibility of the DER plant at the PCC and along the feeder, both above and downstream of the PCC. Requirements depend on the DER, the location, existing condition, and capacities of the feeder. Key concerns are maintaining service voltage within limits for all customers, operating within the ratings of power delivery equipment, managing reverse power, addressing contingencies requiring feeder reconfigurations and protection coordination. In this Section, limits to the individual and aggregate DER, as well as criteria for feeder upgrades are addressed.

9.7 Aggregate and Individual DER Capacity Limits

Based on experience in the EPS, the following AC limits have been established for aggregate large DER for feeders at different circuit voltage levels.

Table 9-1. Aggregate DER AC capacity limits for feeders at different voltage levels

Circuit Voltage	Aggregate Limit	Large DER Size
4.16, 4.8 kV	1 MW	250 kW
7.2, 8.32kV	2 MW	250 kW
13.2 kV	3 MW	250 kW

These aggregate AC limits apply to large DER. They are intended to provide allowance to accommodate residential-scale or small system applicants. If the aggregate AC DER limits are reached, then customers and developers may continue to request connection of systems less than the large DER size.

Once the aggregate limit has been reached, customers are required to build their own lines between the PCC and the POI, with their own poles and within their own right-of-way. LUMA will perform no maintenance on said lines and poles.

Systems greater or equal 250 kW, shall have the ability to use advanced inverter functionality (i.e. an absorbing PF) to ensure that LUMA can mitigate voltage fluctuation or steady state voltage rise as penetration increases. If necessary, LUMA shall specify a PF or volt/VAR curve or other setting at the time of installation or request a change at any time in the future. The flexibility of using these functions contributes to a more stable grid as well.

Note, the 4kV portion of the electric grid is generally older and someday may be converted to a higher voltage and some circuits have a very low peak load, hence the aggregate amount of large systems is limited to 1 MW.

The largest single-phase system at any feeder voltage is limited to 100 kW, based on the need to keep phases balanced.

9.8 Substation Power Transformers Limits

The aggregate of large DER will be limited to 50% of the substation transformer normal rating. In the case of transformers paralleled on the low side, the limit is 50% of the sum of the transformer normal ratings. This usually ensures that the LTC does not operate excessively. Note that small systems (less than the large system size for the circuits' voltage class), may continue to be interconnected when these distribution transformer limits are reached.

The absolute net reverse power limit is 40% of the transformer normal rating. This ensures that locations with transfer capability can operate safely where one transformer load automatically transfers to the remaining transformer upon outage of one transformer. Note that OLTCs can get damaged if regulating voltage when power is flowing in reverse. For this reason, if LUMA finds through its studies that reverse flow at the transformer level is possible, it will include a replacement of OLTC control into the project scope.

Sizing and design requirements are covered in the mitigation options and upgrade requirements section TBD.

Example: 2 transformer station, each with normal rating of 40 MVA. 20 MW of large PV systems are allowed to apply on each transformer. After hitting the 20 MW limit, smaller units may continue to apply. If/when the reverse power reaches 16 MVA (0.4 x 40MVA), the circuits on that transformer will be fully restricted from receiving any more DERs.

9.9 Thermal Operating Limits

An Interconnection shall not thermally overload any electrical equipment based on manufacturer ratings and industry practices for determining limits. Thermal limits shall be based on system rating during normal operation. This includes loading capacity of conductors as determined by size, conductor material, and duct configuration. In addition, the design must ensure that circuit losses on the distribution feeder are equal or less that 3% demand loss and 3% annual energy loss.

Curtailment systems may be used to mitigate overloads and are an accepted practice to assure that thermal limits are not exceeded.

9.10 DER Customers with Multiple Radial Services

LUMA will determine if a DER can operate under alternate supplies during the Interconnection assessment phase. LUMA may determine one of the three scenarios is possible, and the customer will be informed accordingly:

1. The DER can operate under all alternate supply scenarios and only need to be directed offline during the transfer to avoid out of synchronism breaker closing, being permitted

to energize until it is moved from the alternate supply to the main supply by a break before make transition.

2. The DER cannot operate under all alternate supply scenarios, due to planning criteria violations or safety reasons.
    a. If a direct transfer trip is in place, the DER will receive the trip signal which will remain asserted until the customer is transferred from the alternate supply back to the main supply. If a Direct Transfer Trip is not employed, and the customer transition to the alternate feed is automated, it must trip the generator prior to transfer and must prevent the generator from paralleling with the alternate feed.
    b. If no direct transfer trip is in place, and the transition is manually operated, the DER will be directed offline via Operator-In-Charge (OIC) communication and will need to remain offline until communicated by the LUMA OIC, when the DER OIC will be informed that the customer has been transferred from the alternate supply to the main supply. If the customer is able to do the transition, then a key lock out system must be employed such that removing the key from the primary feed will disconnect the generator from all sources, prior to the customer using the key to transfer their load to the alternate feed.

For customers that have multiple normal services, the addition of DERs is limited to avoid any condition where more generation or load is connected to any service than it can accommodate. Limiting conditions include:

- Load is at peak and local generation is lost, and
- local generation is at maximum output and load trips off.

In both conditions circuit ratings and voltage must remain within normal limits for loss of either generation or load. The DER system may be connected to:

- A single circuit that may be reconfigured by LUMA to provide an alternative service on the loss of the primary service.
- A dual service where either one of the incoming feeders connects to the DER at the DER operator’s discretion. When switching from one feeder to the other the DER will need to be disconnected and then reconnected to the new service.
- A dual service where both feeders can supply the DER at one time or either one of the incoming feeders connects to the DER at the DER operator’s discretion. Both feeders can be connected either for a short period of time or longer period based on LUMA operational requirements.

9.11 Reconfiguration of Radial Circuits

Circuit reconfigurations of a feeder are not allowed to accommodate an Interconnection. Circuit reconfiguration may occur for accommodating load and should be beneficial to the EPS– improving voltage, loading, transfer capability, etc.

For a new high-side breaker position, the construction and/or modification of the existing bus will be required. The new position shall not utilize a planned future transmission line, distribution transformer, mobile unit, or planned capacitor position.

9.11.1 Distribution Automation ("DA") Schemes

Experience has shown that DA schemes can be compromised by large DER systems in concentrated areas. Both fault location and switching can become more difficult.

The DER shall not interfere with Distribution Automation (DA) schemes. Where DERs may interfere with existing DA schemes (e.g., FLISR- fault location, isolation, and service restoration), the following design requirements shall apply:

- DERs applying within Distribution Automation zones shall not interfere with the proper operation of the scheme. The range of load and DER output levels are checked to ensure proper operation under all conditions otherwise mitigation is required at customer expense.
- DERs proposed within existing protection and automation schemes must be integrated and interoperable to maintain existing levels of reliability.
- Systems 250 kW and greater, applying to circuits that have or can have DA schemes, will be required to have telemetry. This will provide monitoring of electrical parameters and in the future, control capability that can be exercised during reconfiguration.

9.11.2 Load Transfers

Interconnection of large DERs may prompt a study to determine if there are issues for any LUMA planned load transfers. These transfers may be to and from circuits with DERs, and shall be analyzed for the following conditions:

- Load, voltage, fault current, and flicker criteria must be acceptable with DERs in-service and off-line.
- Distribution automation and protection schemes must operate correctly under all conditions.
- Additional fault current contribution from the DER shall not exceed 85% of the fault current capability of equipment belonging to the EPS or primary service customers.
- Permanent load transfers with active DERs are only allowed when engineering review of loading, voltage, flicker, fault current criteria, and protection schemes indicates there are no issues.
- Temporary load transfers are permitted for short term or emergency restoration conditions.
- Automatic and manual switching will be evaluated as part of the DER Interconnection review approval process. Any issues that create loss of functionality will need to be addressed.
- DER Reverse Power Limits

9.11.3 General

Reverse power flows shall not be allowed through any electric system components not designed to accommodate it. Distribution components that may not be designed to accommodate reverse power flow include:

- Voltage regulators,
- Distribution power transformers,

- Circuit terminals,
- Substation metering.

For example, voltage regulators will not operate correctly under reverse power unless they are reversible and set for Cogen or DG mode. They should also have source sensing activated to allow them to operate in a reverse mode if the circuit is reconfigured with the substation source on the other side of the voltage regulator. Many power transformers are not protected for reverse power flow when there is a ground fault on the high-side delta connection and causing ground fault overvoltage.

9.11.4 Reverse Power and Safety Buffers

Components not specifically designed to accommodate reverse power flow require operating buffers to ensure that periods of low load coinciding with periods of high DER generation do not result in reverse power. These buffers are needed for unforeseen conditions such as changes in weather, economics, factory schedules, etc. affecting the load profile on a circuit, section, or power transformer.

Operating buffers to prevent reverse power on non-upgraded circuit terminals, voltage regulators, and distribution power transformers shall be as follows:

- Power flow must be monitored and have adequate protection settings when, or if, the reverse power buffer is reached. The safety buffer requires 20% more native (gross) load than generation to prevent reverse power. For solar there must be 20% more minimum daytime (9am-3pm) native load than generation. If a feeder terminal relaying/metering is not adequate, upgrades may be required.
- When the aggregate full output capacity of all downstream DERs equals or exceeds 80% of the minimum phase native (gross) loading, systems 25kW or less can be added to the feeder(s) until reaching the minimum size buffer in the following table.
- If minimum daytime load thresholds are not met on a substation power transformer, then the feeders served by the transformer shall be restricted to small applications (50 kW or less). When observed minimum net load falls below the minimum buffer in the following table, (minimum daytime load for solar DER), the feeder shall be restricted from all future applications. (In either case, if the applicant desires to pay for necessary upgrades, their project may move forward).

Note for non-solar DERs:

- Minimum load should be used, not daytime minimum load, as non-solar DERs do not necessarily produce peak output during daytime hours. This also includes Energy Storage Systems that can export to the grid at the time of absolute minimum load.

Note for solar DERs:

- Daytime (9am - 3pm) minimum load shall be used. Local daytime minimum load should be considered the lowest annual daytime load going through the lowest loaded phase of the distribution system. When available, that should be used to calculate the 3-phase power which can be used to check for adequate buffer.

- Should daytime minimum load information not be available, the minimum all-time load of the circuit shall be used for establishing the operating buffer.
- If neither the daytime minimum load information nor circuit minimum all-time load information is available, a reasonable method of estimating the minimum load shall be used, i.e., 12-30% of peak depending on the load composition of the circuit.

9.11.5 Reverse Power Safety Buffer Requirements

In addition to the requirements discussed above, minimum size of the operating buffer for equipment at its rated voltage shall be in accordance with the following table.

Table 9-2. Minimum size of buffer zone for equipment by circuit voltage level

Circuit Voltage Level	Minimum Size of Buffer Zone (Total 3 Phase Power)		
	Voltage Regulators	Distribution Power Transformers[1]	Circuit Terminals[2]
4.16 - 8.32 kV	100 kW	200 kW	150 kW
12 – 13.8 kV	200 kW	500 kW	250 kW

[1]Limit does not apply to substation transformers with grounded high-side winding
[2] Upgrade is at the discretion of LUMA. Terminals rarely need to be upgraded.

Specific limits and options may also depend on the application and will be addressed in Interconnection technical review. Typical application issues related to reverse power include:

- Uni-directional voltage regulators without DG or Cogen Mode or auto-source sensing,
- Transmission-level reverse power limitations,
- Need for 3V0 protection at sub, or power limits, and
- Transformer life/rating concerns.

9.12 Feeder Upgrade Options and Requirements

9.12.1 Service Transformer/Secondary Conductor Upgrades

The following analysis and design requirements shall apply where an Interconnection less than 50 kW requires an upgrade to the service transformer and/or secondary conductors. A voltage rise analysis should be performed for any project to determine if the transformer, secondary conductors, or service wire should be upgraded. If available, AMI voltage data will be used to support the voltage rise analysis. If an upgrade is required, the least-cost upgrade correcting the issues should be selected.

For larger primary connected, 3 phase systems, the following transformer requirement may apply:

- Any DER greater than or equal to 250 kVA may require load taps (+/- 2.5 and 5% typically).
- For DERs in areas where a voltage level is being retired, the developer will be required to provide a dual voltage transformer and associated equipment rated to operate at the higher voltage level, so that if/when a conversion takes place, the transformer will support the new voltage level.

9.12.2 Sub-Station Power Transformers

The following criteria shall apply where a DER plant Interconnection requires a substation power transformer upgrade:

- The upgraded or new transformer shall be the standard size and standard design of the EPS for the voltage class.
- Circuits with significant DERs should not use line-drop compensation as a Load Tap Changer ("LTC") setting. Line-load drop compensation is not to be used on any new feeder.
- The transformer shall be protected against a high side line-to-ground fault if generation can feed back through the transformer.

9.12.3 Feeder Voltage Regulators

Where a DER Interconnection requires a voltage regulator to be added or upgraded, this must be completed before approval to operate. LUMA will apply the following requirements if reverse power is possible:

- Upgrades will provide for bi-directional operation.
- Upgrades will include a Cogen or DG operating mode and auto source sensing functionality activated to allow proper regulation in case of reverse power and during circuit reconfiguration such as a DA scheme operation
- Added or modified voltage regulators may require coordination with other LUMA regulating equipment. If communication is required, voltage regulators shall be equipped with telemetry to the Operations Center giving operators the ability to change settings and control modes as necessary and for future ADMS volt/VAR control. Interoperability requirements described in section 10 apply.

9.12.4 Capacitor Banks

The following requirements shall apply where a DER Interconnection requires a capacitor bank upgrade or a relocation on the circuit:

- Fixed capacitor banks may be upgraded to switched type, removed and/or installed at a new location, as appropriate.
- LUMA will determine settings for switched capacitor banks in coordination with any DER reactive power response settings, during Interconnection technical review.

9.13 Circuit & Bus Reconfigurations

Circuit reconfigurations are not allowed to accommodate an Interconnection. From time to time, LUMA may perform phase balancing.

For a new high-side breaker position, the construction and/or modification of the existing bus will be required. The new position shall not utilize a planned future transmission line, distribution transformer, mobile unit, or capacitor position.

10. Plant Interoperability

10.1 General Requirements

Requirements for interoperability of the DER is specified in IEEE Std 1547™-2018 clause 10 Interoperability, Information Exchange, Information Models, and Protocols. DERs are expected to follow these requirements. This chapter defines additional and/or more specific requirements for LUMA and clarifies which systems must be connected to telecommunications networks for data to be collected and/or exchanged.

10.2 Interoperability for DER Plants

Interoperable telemetry shall be available in all DERs following IEEE Std 1547™-2018 clause 10. These requirements include more extensive monitoring, control, and information exchange requirements covering many parameters including nameplate information, configuration information, monitoring information, and management information. LUMA reserves the right to use the full information that is identified in these requirements. This interface will be utilized (telemetry connected to a communication network) as specified in other areas of this document.

10.2.1 Capability Requirements

Interoperability capabilities include specific protocol and communication performance requirements.

IEEE Std 1547™-2018 specifies standardized communications interface for all DERs that shall be locally available at the DER location. Communications should not depend on vendor specific protocol or remote communication. Any setting changes must be reviewed/approved or initiated by LUMA.

A standardized, local DER communication interface makes it possible for LUMA (or other parties) to perform monitoring and management/control of DERs by deploying an appropriate network. It further allows utilities to collect standardized configuration information, such as nameplate ratings.

10.2.2 Communication Protocol Requirements

Interoperability requirements include specific protocol requirements and communication performance requirements. IEEE Std. 1547™-2018 specifies three applicable protocols: IEEE 2030.5 (SEP2), IEEE 1815 (DNP3), or SunSpec Modbus. LUMA will require DERs to speak the following protocols, depending on the DER's size:

	IEEE 2030.5 (SEP2)	IEEE 1815 (DNP3)	SunSpec Modbus
Less than 250 kW	Allowed	Allowed (see notes)	Allowed
Greater than or equal to 250 kW	Allowed	Required	Allowed

Note: Required protocols must be present. Other interfaces including IEEE 2030.5, IEEE 1815, SunSpec Modbus, or others are allowed if the required interfaced is present.

Additional notes and considerations:

- IEEE 2030.5 is suitable for use in integration communication networks and includes cyber security definitions.
- SunSpec Modbus for small-scale DERs is a simple protocol that is well suited for local interfaces which reduces integration complexity, increasing interoperability.
- IEEE 1815 (DNP3) for large scale DERs is compatible with the EPS SCADA systems and well suited for cohesive integration with DA and DMS for overall distribution optimization.
- When LUMA requires telemetry on systems less than 250kW, output should be DNP3.

10.2.3 Unlock Mechanism Requirement

Some DERs have historically included methods to lockout communication through the local interface, usually with passcode access required. Some vendors may continue this practice even after open standards are required. This proprietary step to unlock the device is only allowed for the initial set up and for certification. The open standard protocols do not support this and cannot unlock a DER that has been locked using proprietary means.

For all inverters certified to IEEE 1547-2018, LUMA requires the unlock mechanism be implemented such that:

- LUMA is not locked out of the communication interface. This is the simplest way to ensure future access. It leaves local communication ports open, like local keypad interfaces.
- Allow devices to be locked but LUMA specifies the messages and passcode(s) by which they are unlocked or locked so that there is a known, common way to gain access to all DERs in the service territory.

LUMA prefers the local DER communication interface not to be locked out (option 1) unless another method is mutually agreed upon. If option 2 is chosen, LUMA requires the IC to provide confirming documentation to LUMA that describes the messages and passcode(s). for each DER.

10.3 DER Communication Interface

10.3.1 DER Plant Requirements

The plant shall provide all telemetry, control, and associated equipment that is required to meet the telemetry requirements highlighted throughout this document. This equipment includes DER interoperability requirements as well as interoperability with the plant controller. This equipment shall meet LUMA specifications.

10.3.2 LUMA Protocol

LUMA will provide and install, at customer cost, telemetry, control systems and protection systems required for interoperability of the DER and plant controller with the EPS communications and control systems. These systems may include such items as communication systems for monitoring DER information, controlling DERs, tripping DER units, and tripping breakers/reclosers.

10.4 Monitoring, Control, and Information Exchange

10.4.1 Inverter-connected Generation Requirements for DER greater than or equal to 1 MW

Any inverter-based generation project that is 1 MW or larger shall be required to install communications to ensure real-time SCADA telemetry.

Any project 1 MW to 5 MW requires:

- Installation of a recloser or acceptable approved device. All SCADA points listed below – except relay failure status
- Polling Rate of 5-minute intervals or shorter as required by LUMA.

Any project that is greater than 5 MW requires:

- Installation of communication equipment to support required polling rate
- All SCADA points listed below
- Polling rates of 30 seconds (analog) and 2-4 seconds (status)

The purpose for real-time SCADA requirements is monitoring the impact of larger installations on the EPS, monitoring performance during transmission and distribution faults, monitoring feeder loading and performance (voltage and frequency) and verifying islanding performance. Inverter communication specifications to be determined based on approved tariff requirements.

LUMA reserves the right to require smart inverter interface where needed with the ability to control volt/VAR settings, ramping, delay times, curtailment, etc. if required to maintain system reliability such as in temporary circuit reconfiguration or abnormal system events.

The following is a preliminary list of SCADA points required. This represents the minimum list of data points required.

- 3 Phase kV (Voltage)
- 3 Phase Amps
- 3 Phase MVA
- 3 Phase MW
- 3 Phase MVAR
- 3 Phase MWh
- Relay Failure Status
- Breaker Status (connected/disconnected)
- Frequency

10.4.2 Machine-connected Generation Requirements

Some generators will require continuous telemetry to the EPS operation facilities. These will typically be large generators, generators involved in wholesale transactions, or generators which are dispatchable by the EPS, depending on PREB requirements for metering on DERs such as PV.

Generators that meet the following criteria require implementing telemetry to the EPS Control Center and telephone communication to the revenue meter. Required telemetry is listed below each criterion. If more than one criterion applies to a generator, the telemetry requirements of each criterion must be met. If the aggregate generation at a site is greater than 10 MW.

- Continuous telemetry is required.
- Instantaneous MW and MVAR of each generator.
- Instantaneous revenue grade MW and MVAR; and cumulative revenue grade MWh and MVARh at all points of Interconnection with the EPS.
- Status of all circuit breaker(s) which can disconnect a generator from the EPS.
- Status of bus tie circuit breaker(s).
- At least one bus kV measurement.

If the generation is involved in sales transactions through the EPS.

- Continuous telemetry required.
- Instantaneous revenue grade MW and MVAR; and cumulative revenue grade MWh and MVARh at all points of service from the EPS.
- Aggregate instantaneous MW and cumulative MWh of all third-party loads inside EPS's control area.

If the generation will be remotely turned on/off by LUMA.

- Continuous telemetry required.
- Instantaneous revenue grade MW and MVAR; and cumulative revenue grade MWh and MVARh at all points of service from the EPS.
- Supervisory control for generator (or generators').

If multiple generators over a large area with an aggregate generation greater than 40 MW are being centrally controlled.

- Continuous telemetry required.
- Aggregate instantaneous MW of all generators.

If the generation, for protection, requires transfer trip communication, then generation site transfer trip communication status shall be telemetered.

Generators that do not participate as capacity resources must provide instantaneous real power data only if they are:

- 10 MW or larger
- Greater than 1 MW and connected at a bus operating at 34 kV and above

Manufacturer specifications for frequency and voltage protection schemes must be submitted to LUMA for review. If this protection is not an integral part of a listed, manufactured power source Interconnection system, LUMA shall have the right to require testing of the protection device systems at the IC's expense.

11. Plant Revenue Metering

For purposes of this document, revenue metering shall refer to the meter or meters used for billing purposes and the associated current transformers and potential transformers (collectively known as "instrument transformers"), communications equipment, and wiring between these devices. The basic configuration consists of bidirectional revenue grade metering at each point of Interconnection with the EPS. Additional separate revenue metering for the gross output of the generation and for auxiliary retail loads may be required, depending on the generation capacity, telemetry requirements, applicable contractual restrictions, and associated rates, additional separate revenue metering for the gross output of the generation and for auxiliary retail loads may be required.

All revenue metering equipment must comply with applicable revenue metering specification section, PREB's applicable regulations and requirements covering revenue metering, as well as technical requirements for the location provided by LUMA.

Minimum Revenue Metering Requirement			
Meter	**DER**	**Descriptions**	**Communications**
Self-Contained Meters	≤10 kW or ≤1 MW	• Accuracy revenue meter, (±0.2% Accuracy class) and be fully electronic (solid state electronic meter). • Minimum two channels with separate energy readings (kwh received and Kwh delivered). • Memory capacity to record consumption at intervals • one hour with a minimum of two memory channels. • Be able to communicate through the remote metering system of EPS • Optical Port • Applicable Standards ANSI C12.1 / C12.10 / C12.20	• RF • Power-Line Carrier
Transformed Rated Meters	≤10 kW or ≤1 MW	• Accuracy revenue meter, ((±0.2% Accuracy class) and be fully electronic (solid state electronic meter). • Have measurement in four quadrants, measuring real energy and reactive, received and delivered. • Have memory capacity to record a minimum of sixty	• RF • Power-Line Carrier • Cellular

		• days of consumption in fifteen-minute intervals, with a minimum of seven memory channels that register: delivered and received kw, kva and kvar and square volts time for all three phases. • Be able to communicate through the measurement system remote of EPS • Optical Port Capability • Applicable Standards ANSI C12.1 / C12.10 / C12.20	
	>1 MW	• Accuracy revenue meter, ((±0.2% Accuracy class) and be fully electronic (solid state electronic meter). • Power Quality Analysis • harmonic distortion • voltage sag and swell detection • waveform capture • Frequency • Current • Voltage • Delivered / Receive ▪ Apparent power total ▪ Power factor total ▪ Apparent power per phase ▪ Power factor per phase ▪ Active power total ▪ Active power per phase ▪ Reactive power total ▪ Reactive power per phase • Have measurement in 16 quadrants, measuring real energy and reactive, received and delivered. • Have memory capacity to record a minimum of sixty • Be able to communicate through the measurement system remote of EPS • Optical Port Capability • Applicable Standards ANSI C12.1 / C12.10 / C12.20	• RF • Power-Line Carrier • Ethernet • Cellular • SCADA

Supplementary Note: Most jurisdictions require generation and auxiliary metering to be able to connect to an Advanced Metering Infrastructure (AMI) system or any other system that LUMA requires.

Definitions:

- RF - Radio frequency communications, most used in AMI system
- Power Line Carrier (PLC) - Carrier data on an electrical conductor.
- SCADA - Supervisory Control & Data Acquisitions

12. Commissioning and Verification Requirements

12.1 General Requirements

This section covers several steps to verification that the Interconnection meets requirements and can be commissioned. It covers a commissioning process including configuration of DER functional setting, evaluation of documentation, determination of tests required to be completed before witness testing. References to determine test requirements that depend on the plant size and type, as well as any specific protective relay test requirements are provided. This section also covers recommissioning and periodic testing.

Specific requirements for each project will be communicated to the customer/developer. These requirements will be a subset of the items found in this section.

12.2 DER Commissioning Process

The DER facility commissioning process shall be planned and carried out by the customer after construction is completed and the site is ready to be energized. At a minimum, the scope of the commissioning process to be performed shall include commissioning tests specified by IEEE Std 1547™-2018, clause 11.2.4.3 - DER as-built installation evaluation, clause 11.2.5 - Commissioning tests and verifications, and clause 11.3 - Full and partial conformance testing and verification. The commissioning process shall verify that the facility does not create adverse system impacts to the electric grid and to other customers served by the grid.

12.3 Configuration of Functional Settings

Prior to commissioning tests, the IC shall configure the DER facility's functional settings by means of one of the following options:

- Option A: Selection of a manufacturer-automated profile (MAP)
- Option B: Use of a configuration and validation toolkit that uses the local DER communication interface
- Option C: Integration with the EPS's DER settings requirements or if applicable, the EPS DER management system (DERMS)

12.4 Evaluation of Documentation

Prior to the performance of commissioning tests by qualified personnel, LUMA will evaluate the on-site documentation to confirm that it is consistent with the application and other required project documentation. This DER evaluation will determine whether commissioning can proceed and the level of commissioning that is required. Certain commissioning tests need to be completed by the IC before Witness Testing can take place.

Identification of the commissioning tests to be performed will be dependent on the results of the documentation evaluation prior to commissioning and whether the RPA is at the PCC or PoC as defined by IEEE Std. 1547-2018™. Commissioning tests for DERs with RPA at the PCC shall be performed per IEEE Std. 1547-2018™ "Table 43 – Interconnection test specifications and requirements for DERs that shall meet requirements at the PCC" and as per guidelines, in the latest IEEE Std. 1547.1. Commissioning tests for DERs with RPA at the PoC shall be performed per IEEE Std. 1547-2018™ "Table 44 – Interconnection test specifications and requirements for DER that shall meet requirements at the PoC" and as per guidelines in the latest IEEE Std. 1547.1.

12.4.1 Review to Confirm As-Builts

The following installed equipment information is required in a final as-built plan before witness testing for confirmation of consistency with previously provided documentation:

Equipment	Information Required
Inverter	- Ratings: Mfg., Model, Rated kW, V on the application will be compared to equipment installed in the field. - Inverter Firmware Version - Inverter Settings
Interconnection transformer[1]	Load side winding connection, High side winding connection, Primary Voltage, Secondary voltage, Rating, and % impedance if customer owned. If owned by the EPS, a contractor supplied picture of the transformer with its size and ID number clearly visible will be used to verify information in GIS. This can speed up secondary voltage rise analysis and service transformer adequacy where data may not be complete in GIS.
Primary fuse / recloser[1]	Rating / Settings
Primary PTs for Ground Fault Protection[1]	The EPS primary PT's shall be wired to customer load side relay to provide Device 59G or Device 27/59 protection for Area EPS Faults

[1] Information not required for Interconnections ≤ 25 kW.

12.5 Commissioning Tests

12.5.1 Protective Relay Tests

Qualified testing personnel must perform tests on the IC's protective relaying prior to energizing from the EPS. Testing requirements will be evaluated and determined on a case-by-case basis by LUMA, dependent upon the configuration of the proposed generating facility. Portions of the IC's equipment may be energized when the associated testing for that portion has been completed and verified. The following table is provided to serve as guidance and may or may not be prescribed in the IC's relay equipment inspection requirements.

Table 12-1. Testing requirement for relay equipment

Relay Equipment Testing Requirement	Type of Testing
Protection Device Function	Variable – Determined by Relay Type
Acceptance Testing	Test Document Review
Setting Calibration	Witness / Functionality
Tripping Check	Witness / Functionality

Sensing Devices	Test Document Review
Primary Current / Voltage	Witness / Functionality
Telemetry for Protection Scheme	Witness / Functionality

The configuration of settings for the protection systems shall be the settings previously provided by the IC to LUMA and approved by LUMA. These settings shall not be altered during commissioning without the authorization of LUMA.

Additional requirements for tests and verification of the DER system is specified in IEEE Std 1547™-2018 clause 11 - Test and Verification Requirements. These include different commissioning requirements based on whether the RPA is at the PoC or PCC and whether the type testing performed was on the DER Unit, DER System or Composite system and the results of the DER evaluation performed before commissioning.

12.5.2 Plant Commissioning Tests

Commissioning requirements are dependent on the size of the DER, DER certification, and whether the RPA is PCC or PoC as identified in IEEE Std 1547™-2018. The following criteria will be considered to identify the commissioning test requirements of the IC.

- Certification of DER for RPA at PoC or DER System for RPA at PCC. Classifications include DER Unit (PoC), DER Composite for PoC compliance, DER System (PCC), or DER Composite for PCC Compliance.
- Results of DER evaluation by LUMA.

Commissioning tests shall be performed according to the appropriate requirements of IEEE Std 1547™-2018 clause 11 and in accordance with IEEE Std. 1547.1™. Commissioning tests shall be performed by qualified personnel. For DER systems with plant controllers, commissioning tests shall include the plant controller. The results of the commissioning tests will be evaluated by LUMA before witness testing can take place.

In addition to the commissioning test requirements identified in IEEE Std 1547™-2018 smarter inverter settings shall be verified, and protective relaying shall be tested as identified in Section 12.5.1 on Commissioning Protective Relaying for Feeder Protection and Communications of this document. Commissioning is also required for telemetry systems depending on DER size and application. Note that additional commissioning and witness testing requirements for Secondary Network can be found in Section 12.5.3.

A commissioning checklist can be found in Appendix F. The commissioning checklist identifies general commissioning requirements. These requirements are based on common DER configurations and levels as identified in Appendix B. These configuration levels are based on several parameters including:

- *This section is to be completed as Appendix F is finalized.*

12.5.3 Required Witness Tests

Before Parallel Operation with the EPS , and after completion of commissioning tests, additional witness testing may be required and inspected by EPS Operator. The IC is responsible for providing qualified personnel who will complete all required tests. Witness testing is generally required for larger generators. LUMA reserves the right to require witness testing in all DER Interconnected scenarios. The following table identifies witness tests that must be performed in accordance with requirements described above.

Applicability	Test	Description
If telemetry required	Cease to energize and trip test	Send command to cease to energize and trip the DER and measure time to shut off.
	Anti-islanding	Open isolation device and measure time for inverter to shut off - ≤ to 2 seconds
All sizes	Reconnection Test	5-minute delay before reconnection. During testing open 3 phase source multiple times after initial opening to verify remains disconnected for at least 5 minutes. – Stay disconnected for ≥ 5 minutes
Required for systems over 25kW	Load Rejection Overvoltage Test	DER facility must cease to energize and trip within 120 cycles after loss grid or: o Maximum RMS Voltage Produced by DER at PCC ranging from 1.1 p.u. to 1.2 p.u. must not exceed 60 cycles o Maximum RMS Voltage Produced by DER at PCC ranging from 1.21 p.u. to 1.5 p.u. must not exceed 10 cycles o Maximum RMS Voltage Produced by DER at PCC ranging from 1.51 p.u. to 2.0 p.u. must not exceed 3 cycles
Where system output must be limited to a certain value	Power Limit Function	Set power limit below current power export. Record response to power limit.
Required for systems over 25kW	Radio Frequency Interference Test	Use a handheld AM Radio to determine if there is RFI during inverter output. RFI will generally increase as inverter output increases but does not go away until inverter shuts off.
Required for systems over 25kW	Current harmonics test	Measured at the PCC
If telemetry required	Telemetry/SCADA	Measured values include kV, Amps, and kW
Required for systems over 25kW	Primary Metering	Measured values include kV, Amps, and kW
Test required if system GT 500 kW and primary voltage LT 5kV, GT 3 MW for voltages GE 5kV and LT 15 kV, GE 4 MWs for voltages GE 1 kV and LT 30 kV, and GE 5 MWs for voltages GE 30 kV and LE 69kV	Primary PTs for Ground Fault Protection	LUMA primary PT's shall be wired to customer load side relay to provide Device 59G or Device 27/59 protection for Area EPS Faults - Identify relay manufacturer, model, and applied relay settings in P.U. (kW) and T.D. (Seconds). - Identify relay test values and measure values in P.U. (kW) and T.D. (Seconds)
Where DTT required	Direct Transfer Trip (DTT)	Confirm DTT signal trips customer protective device to isolate DER.
Required for non-exporting customers	Reverse Power Relay (Device 32)	Installed at the PCC - Identify relay manufacturer, model, and applied relay settings in P.U. (kW) and T.D. (Seconds).

		- Identify relay test values and measure values in P.U. (kW) and T.D. (Seconds) - Verify DER either trips off or isolates to prevent export of power to the Area EPS at the PCC.

Special commissioning and witness test requirements for secondary networks can be found in Section 12.5.3.

12.6 Recommissioning

Recommissioning is required, under certain circumstances, after the original commissioning and witness testing is completed. The extent of recommissioning is dependent on the reason for the commissioning and the effect on the DER Interconnection. Partial recommissioning may be required as part of the regular testing of basic functionalities of protective and control functions. These tests are expected and may need to occur in time frames typically ranging from every year to every 10 years depending on manufacturers recommendations and LUMA's experience with similar equipment. Section 12.7 has further information on periodic testing.

Circumstances that may lead to event-based DER recommissioning include:

- Change in version of software, software or parameter modifications that change rated values,
- Replacement of major components or modules with a new version,
- Required changes in the plant telemetry, or changes in major equipment (e.g. transformers, circuit breakers, etc.),
- Change in operating mode that was not previously commissioned.

Recommissioning may be scheduled, triggered based on notification of plant change requirements may occur due to automated notices of operation outside of expected parameters. These may include mis-operation of the DER, mis-operation of protective systems, or excess harmonics are detected at the PCC. LUMA will determine whether recommissioning may require the full set of tests required of a new facility or a subset of these tests will be sufficient. The level of testing is dependent on the reason for the recommissioning.

12.7 Periodic O&M and Testing

12.7.1 Periodic testing Requirements

The IC must provide LUMA with calibration and functional test data for the associated equipment upon request. Minimum recommended intervals are indicated below:

Device	Frequency
Relays	Every three years
Communication Channels	Every three years
Circuit breakers	Every three years
Batteries	Per IEEE 450 - 1995 Standard

The customer must include the identities and qualifications of the personnel who performed the tests. LUMA personnel may need to periodically witness the testing.

Additional requirements for periodic testing are specified in IEEE Std 1547™-2018 clause 11.2.6 - Periodic Tests and Verifications. These requirements include changes in functional software or firmware changes, changes in hardware components of the DER, and changes in protection functions or settings.

At a minimum, the customer should provide test results per the manufacturers recommendations.

12.7.2 Operating and Maintenance Requirements

LUMA routinely performs maintenance on its system. While the LUMA tries to perform all maintenance on a scheduled basis, sometimes emergency maintenance is necessary. For both scheduled and emergency maintenance, the work is generally planned to minimize both customer inconvenience and company cost. As a prudent cost control, LUMA schedules most routine maintenance during normal daylight working hours. To this end, LUMA routinely transfers customer load among electric sources, so that the customers involved remain in service while the maintenance work is being performed. For most customers involved this “switching” is transparent.

When a customer is Operating in Parallel a generator with the electric system, it may not be possible to do a load transfer with large DERs remaining in service. If the situation is not an emergency, possible action may include the following:

- The customer may choose to turn off the generation and continue electric consumption. Electricity may be purchased from LUMA under the provisions of the Standby Service Rate.
- The customer may choose to turn off the generation while curtailing electric consumption. Electricity may also be purchased from LUMA under the provisions of the Standby Service Rate.
- The customer may request LUMA to perform the work at times when the customer’s generation is not being operated. The customer is responsible for, and will be billed for, the full extra cost that LUMA experiences due to the request.
- The customer’s generation and load may be switched away from the EPS while the work is in progress. This option is available only if the customer’s electric system can operate independently of the EPS. Notwithstanding the above, switching equipment capable of isolating the customer’s generation from the EPS shall be accessible to and under the exclusive control of LUMA always. At its option, LUMA may choose to operate the switching equipment if, in LUMA’s opinion, continued operation of the customer’s generation in connection with EPS may create or contribute to a system emergency, an unsafe condition, or interfere with service to other customers.

The switching equipment referred to above must be accessible to and capable of being operated and locked by LUMA’s personnel. This equipment must provide a visible break in the circuit.

13. Microgrids, CHP/Cogen

This is currently serving as an outline- more information will be added to this section for the final version.

13.1 CHP and Cogen

Combined heat and power (CHP) and Cogeneration facilities generally rely on synchronous machines or induction machines for coupling of the generator to the power system. The reader should refer to the relevant sections of the document that speak to requirements for each of these technologies.

Over and above these technical requirements, the proponent of a CHP or Cogen facility shall provide LUMA with a planned operating schedule for the facility, documenting the anticipated running schedule and power output on at least an hourly resolution. If the proponent expects that operating strategy to change throughout the week or the year, they may provide additional schedules for day of the week or season, as appropriate. This will facilitate completion of the Interconnection Study and accurate estimation of any system upgrades, as required.

13.2 Microgrids

The microgrid technical requirements outline the major considerations needed to support safe integration of a customer driven microgrid. In this case, the customer microgrid considers the Point of Interconnection to be the customer's Meter, and hence no EPS assets are involved in islanded operation of the system. The technical requirements provide overall guidance into the major technical considerations in the design of the microgrid and the mandatory requirements that shall be met for Interconnection of the microgrid to the EPS Distribution System.

Technical requirements specific to the DER that are part of the microgrid are covered in the main document, the current section outlines those requirements distinct in the case of a customer microgrid. These additional requirements shall be met in order for the microgrid to connect to the system, safety Operate in Parallel with the distribution grid and in islanded mode, and to permit sufficient visibility to EPS Distribution System operations to manage operation of the microgrid together with the Distribution System.

Outline of contents:

Microgrid distributed energy resources

- Grid forming generators
    - Battery storage inverters
    - Synchronous generators
    - Guidance on sizing of grid-forming generators
- NEM DER or non-participating DER
    - Operational modes
    - Normal grid-connected operation (covered predominantly by main technical requirements)

Islanded operation modes

- Voltage and frequency control

  - Load shedding
  - Generation dispatch
  - Islanded operation duration considerations

Transition approaches

  - Seamless
    - Grid-connected to islanded operation
    - Islanded operation to grid-connected
  - Break-before make transition
    - Grid-connected to islanded operation
    - Islanded operation to grid-connected

Microgrid Point of Interconnection
Protection requirements
Grounding requirements
Communication and interface requirements

  - Microgrid controller
  - DERs
  - Metering

- Testing and commissioning
  - Minimum requirements (in addition to DER Interconnection testing requirements for DERs part of the microgrid)
  - Islanded operation test
  - Resynchronization test

14. Transmission and Sub-Transmission Interconnections

This is currently a placeholder. This section will be filled out for the final version of this document.

Appendix A: Reference Standards and Guidelines

Industry Standards

- IEEE Standards 1547, 519, 1453
- ANSI C84.1, C62.92, C37
- UL 1741

PREB Regulations

Industry Association Guidelines

- CBEMA and ITIC Requirements
- IREC Guidelines, Solar ABCs
- LUMA System Planning and Design Criteria for LUMA

Appendix B: Common DER Configurations Protection and Interconnection Group (One line Requirement)

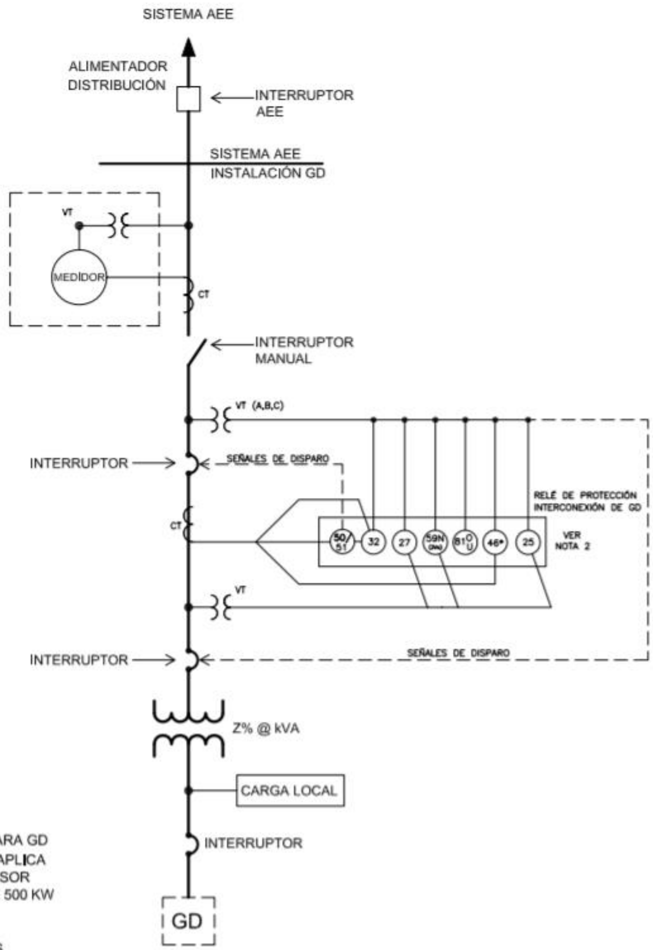
Common DER Configurations						
Config 1	25 kW or less	Config 1A	Lab Certified	Inverter Based	Radial	Exporting or Non-Exporting
		Config 1B	Not Lab Certified	Inverter or rotating machine	Radial	
		Config 1C	Lab certified or Not Lab Certified		Area or Spot Network	Non-Exporting
Config 2	>25 kW and ≤250 kW	Config 2A	Lab Certified	Inverter Based	Radial	Exporting
		Config 2B				Non-Exporting
		Config 2C	Not Lab Certified	Inverter or rotating machine		Exporting
		Config 2D				Non-Exporting
		Config 2E	Lab Certified		Area or Spot Network	
		Config 2F	Not Lab Certified			
Config 3	>250 kW and ≤2000 kW	Config 3A	Lab Certified	Inverter Based	Radial	Exporting
		Config 3B				Non-Exporting
		Config 3C	Not Lab Certified	Inverter or rotating machine		Exporting
		Config 3D				Non-Exporting
		Config 3E	Lab Certified		Area or Spot Network	
		Config 3F	Not Lab Certified			
Config 4	>2 MW and ≤10 MW	Config 4A	Lab Certified	Inverter Based	Radial	Exporting
		Config 4B				Non-Exporting
		Config 4C	Not Lab Certified	Inverter or rotating machine		Exporting
		Config 4D				Non-Exporting
Config 5	>10 MW	Config 5A	Lab Certified	Inverter Based	Radial	Exporting
		Config 5B				Non-Exporting
		Config 5C				Exporting

		Config 5D	Not Lab Certified	Inverter or rotating machine		Non-Exporting

Appendix C: Typical One-Line Diagrams

The following One-Line Diagrams are intended to be typical or representative samples of various types and sizes of Generating Facilities that are connected to and Operate in Parallel with the EPS and do not purport to cover every possible case. Each site will have to be specifically designed considering the unique characteristics of each installation, the specific location of the Point of Common Coupling and the operating and contractual requirements for that site. The listed voltages on the diagrams represent nominal values. The actual voltage is dependent on the Interconnection location on the EPS circuit.

1.1. Diagram 1 – Synchronous Generator Connected to the Primary Distribution Network

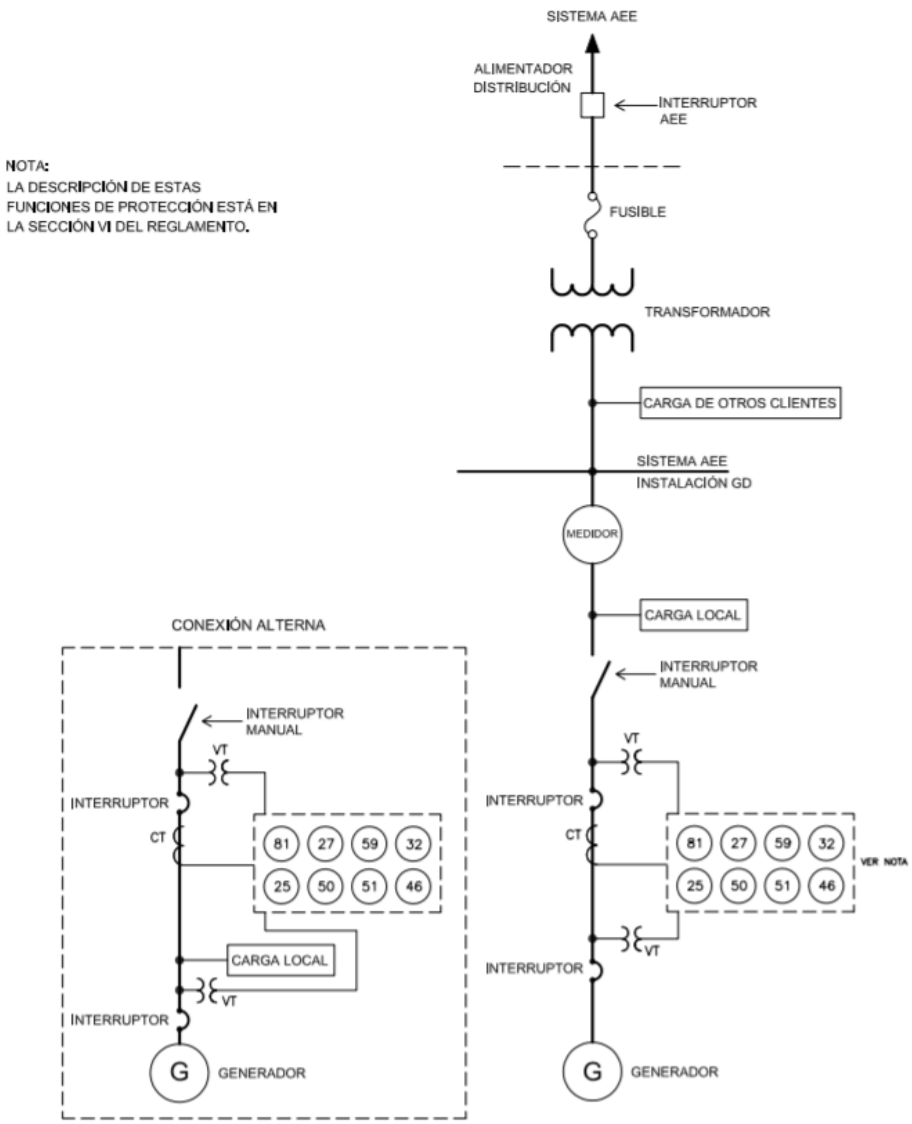


NOTAS:

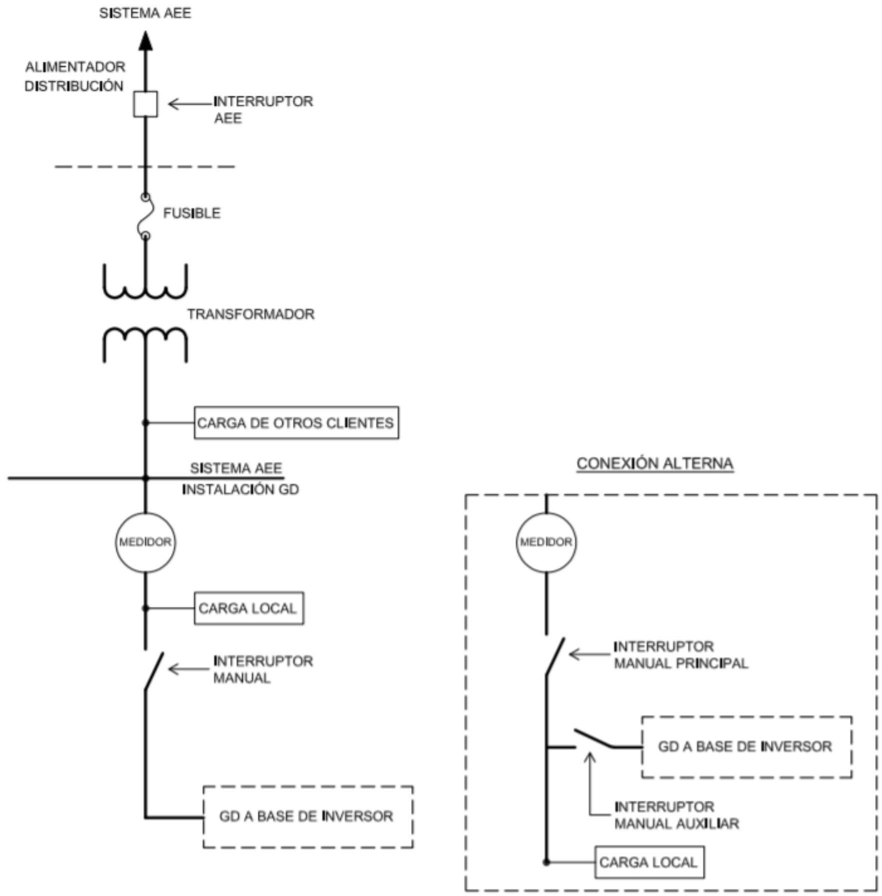
1. ESTE DIAGRAMA APLICA PARA GD ROTACIONALES. TAMBIÉN APLICA PARA GD A BASE DE INVERSOR CON CAPACIDADES DESDE 500 KW HASTA 1 MW.
2. LA DESCRIPCIÓN DE ESTAS FUNCIONES DE PROTECCIÓN ESTÁ EN LA SECCIÓN VI DEL REGLAMENTO.

* DE SER NECESARIO

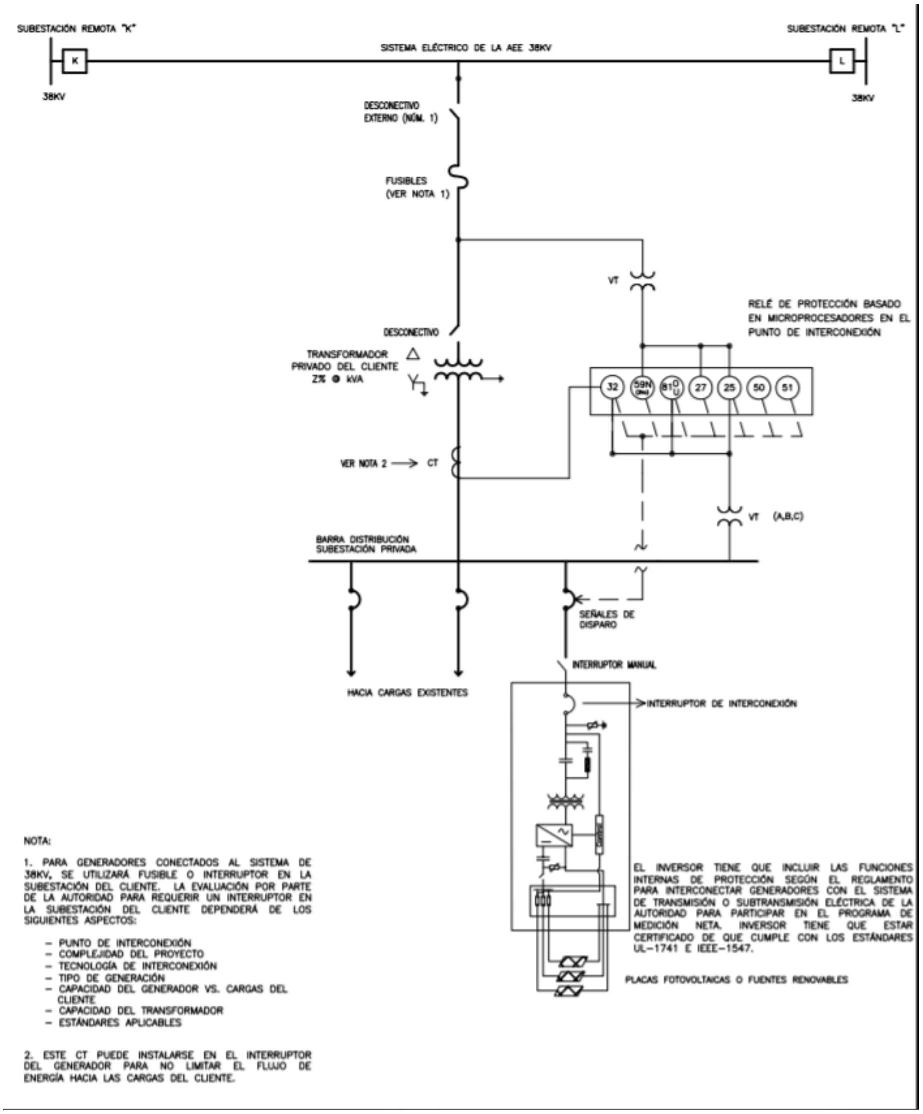
1.2. Diagram 2 – Synchronous Generator Connected to the Secondary Distribution Network



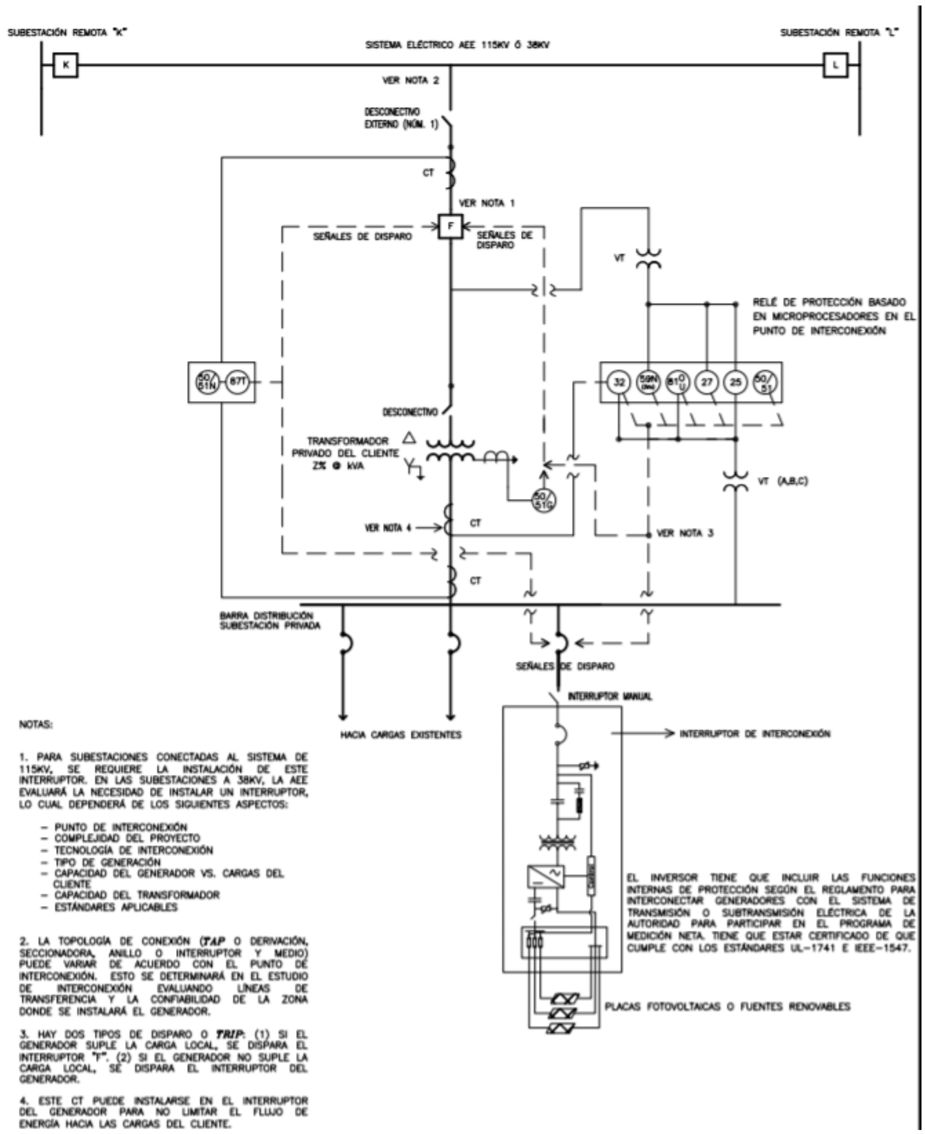
1.3. Diagram 3 – Connection of inverter-based DER to the Secondary Distribution Network



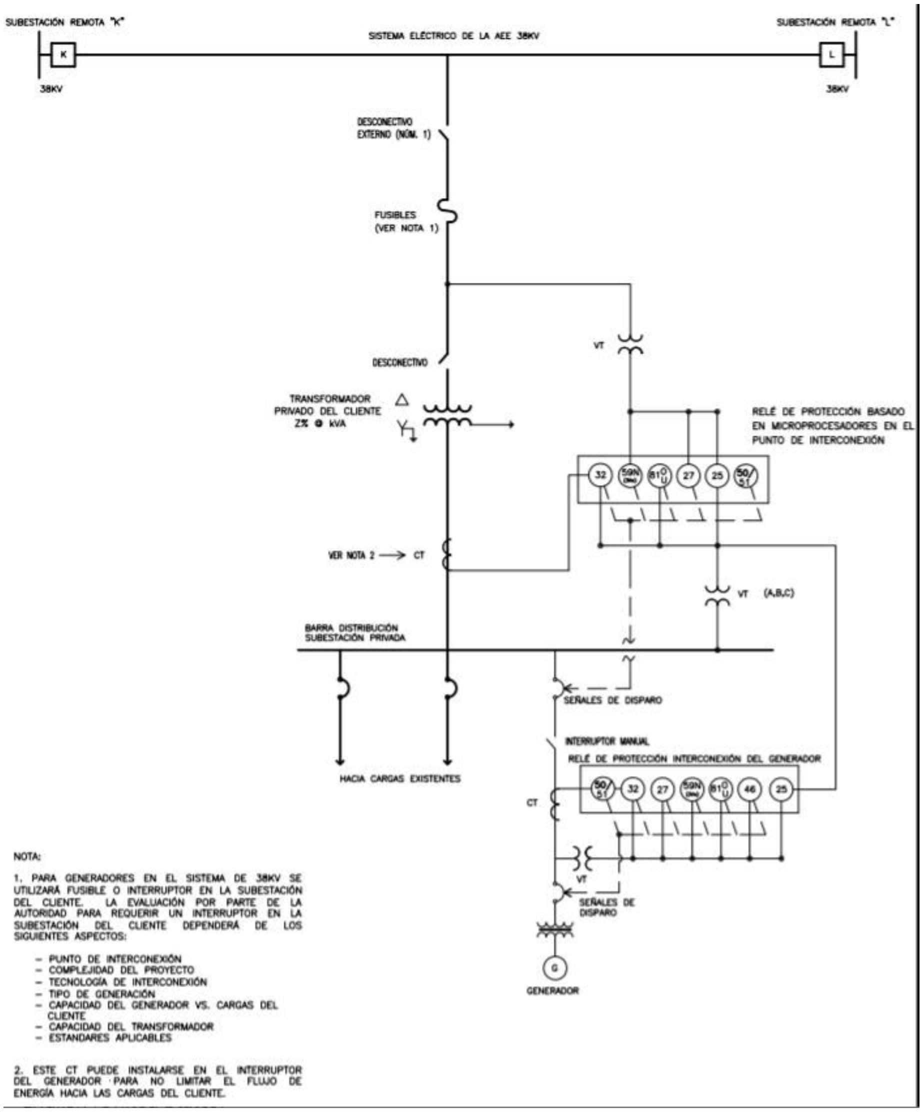
1.4. Diagram 4 – Connection of an inverter to the sub-transmission network (38kV) through fuses



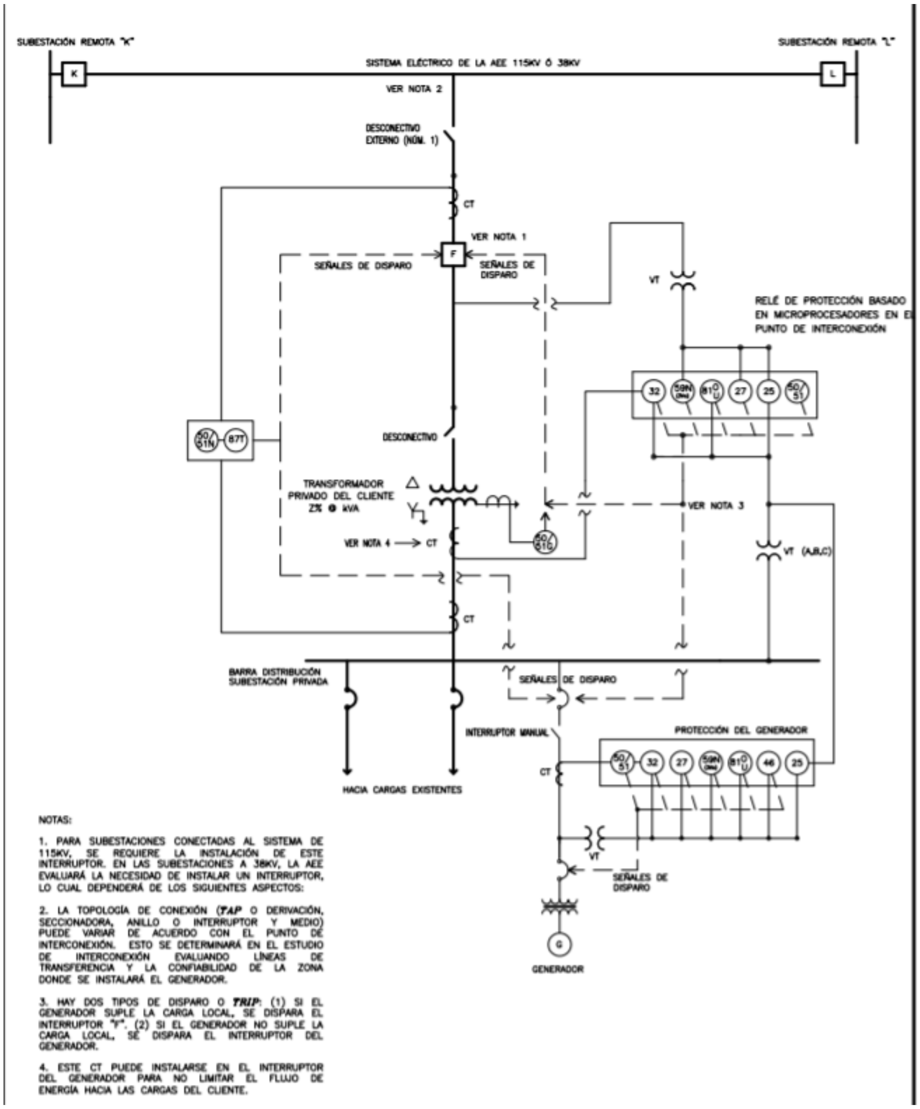
1.5. Diagram 5 - Connection of an inverter to the transmission (115kV) or sub-transmission network (38kV) through switches



1.6. Diagram 6 - Connection of a generator to the sub-transmission network (38kV) through fuses



1.7. Diagram 7 - Connection of a generator to the transmission (115kV) or sub-transmission network (38kV) through switches



Appendix D: Typical Relay Requirements per Plant Configuration (Radial Circuits)

Common DER Configurations			*These are general guidelines for protection requirements and may vary based on IC's total system configuration. Individual protective device functions may be implemented using multifunction relay.+*					
Config 1a	**Config 2a, 2b, 3a, 3b, 4a, 4b**	**Config 1b**	**Config 2d, 3d, 4d**	**Config 1c, 2e, 2f**	**Config 2b, 2d, 3b, 3d, 4b, 4d**	**Config 2c, 2d, 3c, 3d, 4c, 4d**	**Config 1c, 2e, 2f**	**Config 2a, 2b, 2c, 2d, 3a, 3b, 3c, 3d, 4a, 4b, 4c, 4d, 5a, 5b, 5c**
11 - Multifunction Device/Relay - Required protective functions may be implemented in a single multifunction relay								
	✓		✓	✓	✓	✓	✓	✓
21 - Distance or Impedance - Requirement determined by capacity. Does not apply to inverter-based generation								
			✓ Other directional protection may be utilized in lieu.		✓	✓ Other directional protection may be utilized in lieu.	✓	✓
25 - Synchronizing or Synchronism Check (Customer DER location) – May only be required for rotating equipment								
		✓	✓	✓	✓	✓	✓	✓
25 - Synchronizing or Synchronism Check/Backfeed Detection (LUMA substation)								
	✓ May be required when aggregate of all generation exceeds 2 MW per feeder, depending on capacity, to provide back feed detection.		✓ May be required depending on capacity, to provide back feed detection.	✓ May be required depending on capacity, to provide back feed detection.	✓ May be required for inverter-based generation, depending on capacity, to provide back feed detection.	✓ May be required depending on capacity, to provide back feed detection.	✓ May be required for inverter-based generation, depending on capacity, to provide back feed detection.	✓ May be required for inverter-based generation, depending on capacity, to provide back feed detection.
51N - Neutral Time Overcurrent*								
			✓	✓	✓	✓	✓	✓

Config 1a	Config 2a, 2b, 3a, 3b, 4a, 4b	Config 1b	Config 2d, 3d, 4d	Config 1c, 2e, 2f	Config 2b, 2d, 3b, 3d, 4b, 4d	Config 2c, 2d, 3c, 3d, 4c, 4d	Config 1c, 2e, 2f	Config 2a, 2b, 2c, 2d, 3a, 3b, 3c, 3d, 4a, 4b, 4c, 4d, 5a, 5b, 5c
51V - Voltage Restrained/Controlled Time Overcurrent* - May be required depending on capacity.								
			✓		✓	✓	✓	✓
67V - Voltage Restrained/Controlled Directional Time Overcurrent* - May be required for inverter-based generation.								
	✓		✓		✓	✓	✓	✓
81O - Over frequency* - May also be required in a separate relay depending on capacity. Over frequency protection is part of lab certified equipment.								
✓	✓	✓	✓	✓	✓	✓	✓	✓
81U - Under frequency* - May also be required in some configuration to accommodate a separate relay, depending on capacity. Under frequency is a part of lab certified equipment.								
✓	✓	✓	✓	✓	✓	✓	✓	✓
86 - Lock-Out								
			✓		✓	✓	✓	✓
87 - Current Differential* - May be required based on system configuration								
			✓		✓	✓	✓	✓
Power Transformer Protection - As required for system Interconnection								
	✓	✓	✓	✓	✓	✓	✓	✓
Interrupting device - May be required for inverter-based generation depending on capacity and transformer								
	✓	✓	✓	✓	✓	✓	✓	✓
Breaker Failure back-up tripping (BF)								
			✓		✓	✓	✓	✓
Relay Failure Protection/Alarm - May be required if there is a separate protective relay.								
	✓		✓		✓	✓	✓	✓

Appendix E: General Protection Requirements

The protection schemes described in this section are intended to be typical for illustration purposes and not specific design requirements for any plant site or configuration. They are intended to guide the proposed Generating Facility owner or Generator Owner and provide basic information on the types of protection schemes necessary for generator Parallel Operation. These refer to plant rating as well as the EPS distribution feeder voltage.

1.8. Interface (Isolation) Transformer Protection

Typical protection schemes for various size Interface Transformers are illustrated below.

Interface Transformer Protection Up to 10 MVA	10 – 50 MVA	Greater than 50 MVA
· Time/Inst. Over Current or High Side Fuse (38kV and below)	· Transformer Differential · Fault Pressure · Time/Inst. Over Current	· Transformer Primary Differential · Transformer Backup Differential · Sudden Pressure Protection · Time/Inst. Over Current · Over Excitation

1.9. Interconnection Feeder Protection

The protection applied to a line terminal at the Generating Facility's site that interconnects the privately-owned Generating Facility with the EPS will vary depending on the voltage class and existing line relaying scheme at the EPS end(s). Typical protection schemes for various voltage Interconnection lines are provided below. The actual schemes used will vary for each specific site.

Typical Line Terminal Protection Schemes Line Voltage Class	Line Protection Schemes
38kV and below	· Phase & Ground Over current (may need to be directional) · 3-Phase to Ground Connected Under Voltage & Over Voltage (For line terminating in delta or ungrounded wye connected transformer)
100kV and above	· Line protection schemes will follow the requirements outlined in [*Reference will be added when document is finalized internally*.]

1.10. EPS Operator's Islanding Prevention Schemes

- Generating Facilities selling into the EPS grid marketplace that have their under-frequency trip point set to meet EPS under frequency operational requirements (such as 57.5 Hz. for 5 Seconds) essentially removes under frequency sensing as a sensitive means to detect isolation. In this case, other protective measures, such as transfer trip, will be required.
- In cases where a transfer trip scheme is needed to ensure isolation detection, the failure of the transfer trip scheme or communication channel will require that the Generating Facility automatically disconnect from the EPS until the transfer trip scheme is restored.

- If a Generating Facility back feeds a substation distribution transformer with an ungrounded high side winding, a transfer trip scheme will be required. Any installation over 750 kW will require DTT.
- Transfer trip schemes shall only utilize a fiber path as a communication medium.

1.11. DER Generator Protection Schemes

- The protection schemes on Generating Facilities will become more complex as the size of the Generating Facility unit increases. Multi-function microprocessor relays can be used to provide several generator protection functions. However, a second multi-function relay is necessary to provide for a relay failure.
- The Generator Owner should consult the generator manufacturer and national standards to develop the appropriate protection for each generator installation. National standards include C37.102-2006 IEEE Guide for AC Generator Protection and C37.101-2006 IEEE Guide for Generator Ground Protection.
- Some typical protection schemes for various size generators are noted in the following table. The actual schemes required for each site could vary from these representative samples.

Typical Generator Protection Schemes			
DC Generating Systems with Non-Islanding Inverters	**Induction/ Synchronous Generators Up to 10 MW**	**Synchronous Generators 10 MW - 50 MW**	**Synchronous Generators 50 MW+**
· Over/Under Voltage · Over/Under Frequency (This preceding protection is integral to the Non-Islanding Inverter.) · DC Over current	· Over/Under Voltage · Over/Under Frequency · Directional Power (watt / var) · Phase Over current · Ground Over current · Negative Sequence	· Over/Under Voltage · Over/Under Frequency · Differential · Stator Ground · Loss of Field · Anti-Motoring · Negative Sequence · Voltage Controlled. Over current	· Over/Under Voltage · Over/Under Frequency · Primary Differential · Back Up Differential · 100% Stator Ground · Back Up Stator Ground · Generator Lead Protection · Primary Loss of Field · Back Up Loss of Field · Field Ground · Anti-Motoring · Negative Sequence · Voltage Controlled Over current or Distance Backup · Breaker Flashover · Protection During Unit Start Up & Shut Down · Accidental Energization · Out of Step Protection · Synchronizing Check

Appendix F: Commissioning Checklist

This is currently a placeholder. This section will be filled out for the final version of this document.

Appendix G: Telemetry Options (to be determined when transfer trip not required)

Communication Options for Plants ≥ 2 MW

<table>
<tr><th>Type</th><th>Benefits</th><th>Risk</th><th>Costs</th><th>Timing</th></tr>
<tr><td rowspan="3">Fiber - LUMA installed</td><td>- Ensure scope, cost, and schedule</td><td>- Higher costs</td><td rowspan="3">- Included in Study estimates</td><td rowspan="3">Per LUMA construction schedule</td></tr>
<tr><td>- Highly reliable x5 - 9's</td><td>- Required to run fiber to substation</td></tr>
<tr><td></td><td>- Single spur is less reliable</td></tr>
</table>