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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

MOTION TO SUBMIT ADDITIONAL COMMENTS

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:

1. 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 Interconnection Regulation Draft") to govern the interconnection of distributed generators and inviting LUMA and other stakeholders to provide comments to this Preliminary Interconnection Regulation Draft, on or before July 30, 2021, before initiating a formal rulemaking procedure.

2. On July 30, 2021, LUMA submitted preliminary comments to the Preliminary Interconnection Regulation Draft. See LUMA's *Motion Submitting LUMA's Comments to Preliminary Draft of Proposed Generating Facility and Microgrid Interconnection Regulation* of that date.

3. On November 15, 2021, LUMA submitted additional comments to the Preliminary Interconnection Regulation Draft which were included as proposed revisions or narrative comments marked on the draft.[1] *See* LUMA's *Motion to Submit Additional Comments to Preliminary Draft of Proposed Generating Facility and Microgrid Interconnection Regulation* of that date ("November 15th Motion"). LUMA proposed that the provisions containing detailed technical requirements for interconnection be removed from the Preliminary Interconnection Regulation Draft and be included in a separate document of "Technical Interconnection Requirements" ("TIR") and submitted a preliminary draft of this proposed document ("Preliminary Draft TIR"). *See* November 15th Motion, pages 3-4.

4. On May 19, 2022, LUMA submitted to the Energy Bureau a more comprehensive draft TIR ("Proposed Comprehensive TIR"). *See Motion Submitting Complete Version of Technical Interconnection Requirements Document* of that date ("May 19th Motion"). LUMA explained that, although the Proposed Comprehensive TIR addressed the subject of smart inverters, further elaboration was required to address the complex subject of smart inverter settings in this document. LUMA also informed this Energy Bureau that after going through the rigorous process of drafting the Proposed Comprehensive TIR as a complementary document to the Preliminary Interconnection Regulation Draft, LUMA had additional comments to the Preliminary Interconnection Regulation Draft, particularly with respect to the subjects of DG evaluations,

[1] On October 15, 2021, LUMA had requested this Energy Bureau, to provide LUMA until November 15, 2021, to submit additional and more detailed comments to the Preliminary Interconnection Regulation Draft. *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.

supplemental study cost values, and DG interconnection capacity cap per feeder and that LUMA planned to submit these comments at the appropriate time.

5. On September 9, 2022, the Energy Bureau issued a Resolution and Order ("September 9th Order") requiring LUMA to file the additional comments mentioned by LUMA in the May 19th Motion "regarding the subjects of DG evaluations, supplemental study cost values, and DG interconnection capacity cap per feeder" ("Additional Comments") on or before October 7, 2022. In addition, the Energy Bureau requested stakeholders and other interested persons to provide comments on the version of the Preliminary Interconnection Regulation Draft containing LUMA's comments ("LUMA Proposed IR Draft"), the Proposed Comprehensive TIR document and the Additional Comments by October 21, 2022.

6. On October 7, 2022, LUMA requested an extension to submit the Additional Comments in light of delays caused by the passage of Hurricane Fiona.

7. On October 18, 2022, the Energy Bureau issued a Resolution and Order ("October 18th Order") granting LUMA's request for extension and ordering LUMA to submit the Additional Comments on or before November 1, 2022, as well as reiterated its invitation for stakeholders and interested persons or groups to provide their comments and feedback to the LUMA Proposed IR Draft, the Proposed Comprehensive TIR document, and the Additional Comments.

8. In compliance with the order to submit Additional Comments in the September 9th Order, as the deadline for this submittal was extended by the October 18th Order, LUMA hereby submits its Additional Comments. *See* Exhibit 1. These Additional Comments address the subjects of DG evaluations, supplemental study cost values, and DG interconnection capacity cap per feeder, as well as the subject of smart inverters which LUMA indicated in its May 19th Motion

required further elaboration in the Proposed Comprehensive TIR document. The Additional Comments also include proposed revisions to the Comprehensive TIR document and the LUMA Proposed IR Draft as a result of the comments in the mentioned subjects.

WHEREFORE, LUMA respectfully requests this honorable Energy Bureau to **take notice** of the above, **accept** LUMA's Additional Comments included in Exhibit 1, and **accept** the proposed revisions to the LUMA Proposed IR Draft and the Comprehensive TIR document indicated in Exhibit 1.

RESPECTFULLY SUBMITTED.

In San Juan, Puerto Rico, this 1st day of November 2022.

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

DLA Piper (Puerto Rico) LLC
500 Calle de la Tanca, Suite 401
San Juan, PR 00901-1969
Tel. 787-945-9107
Fax 939-697-6147

/s/ Laura T. Rozas
Laura T. Rozas
RUA Núm. 10,398
Laura.rozas@us.dlapiper.com

EXHIBIT 1

LUMA's Additional Comments

LUMA Additional Comments: Interconnection Regulation and Technical Interconnection Requirements (TIR)

NEPR-MI-2019-0009

November 1, 2022

Introduction

On November 15, 2021, LUMA submitted additional comments to the draft of a new comprehensive interconnection regulation issued by the Energy Bureau on July 15, 2021 in Case No. NEPR-MI-2019-0009 (Draft Interconnection Regulation). LUMA's comments were provided as proposed revisions or narrative comments marked on the Draft Interconnection Regulation. LUMA proposed that the provisions containing detailed technical requirements for interconnection be removed from the Draft Interconnection Regulation and be included in a separate document of "Technical Interconnection Requirements" (TIR) and submitted a preliminary draft of this proposed document (Preliminary Draft TIR).

On May 19, 2022, LUMA submitted to the Energy Bureau a more comprehensive draft TIR (Draft Comprehensive TIR) and indicated to the Energy Bureau that, although the Draft Comprehensive TIR addressed the subject of smart inverters, further elaboration was required to address the complex subject of smart inverter settings. LUMA also informed the Energy Bureau that it had additional comments to the Draft Interconnection Regulation, particularly with respect to the subjects of DG evaluations, supplemental study cost values, and DG interconnection capacity cap per feeder.

On September 9, 2022, the Energy Bureau issued a Resolution and Order in Case No. NEPR-MI-2019-0009 where the Energy Bureau ordered LUMA to file "Additional Comments" on the topics of DG evaluations, supplemental study cost values, and DG interconnection capacity cap per feeder mentioned in LUMA's May 19th submittal. LUMA appreciates the opportunity to participate in the development of the Energy Bureau's Draft Interconnection Regulation and the Technical Interconnection Requirements (TIR). LUMA will address in this document the mentioned subjects, as well as the smart inverter settings mentioned in the May 19th submittal. LUMA looks forward to continuing a constructive collaboration with the Energy Bureau and Stakeholders in the development of the Interconnection Regulation process and additional comments, as follows:

1.0 Smart Inverter Settings

LUMA proposes incorporating the requirements for smart inverter settings into the Draft Comprehensive TIR as an Appendix H of that document and including a narrative and reference to Appendix H in Section 4.1 of the Draft Comprehensive TIR document.

The revised draft of the Draft Comprehensive TIR Document, attached as Exhibit A, includes this revised language in Section 4.1 and the proposed Appendix H, and these changes are marked to highlight the revisions to the previous Draft Comprehensive TIR Document.

2.0 Costs for DG Application

The Draft Interconnection Regulation includes, as Attachment 1, a form of the Generator Interconnection Application. This application indicates, under "Processing Fee or Deposit", the following:

- *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.

LUMA proposes that the language quoted above be revised to clarify the formula for the fee and deposit. The application process applies to both Generating Facilities and Microgrids. Therefore, the portion of the fee based on the capacity of the facility should apply to both Generating Facilities and Microgrids. Accordingly, the formula for the Interconnection Application for the Fast Track Process should read “$100 plus $1.00 per kW of Generating Facility or Microgrid capacity”, and the formula for the study process should read “$1,000 plus $2.00 per kW of Generating Facility or Microgrid capacity towards the cost of the first study”.

Attached, as Exhibit B, is the revised Draft Interconnection Regulation (containing LUMA’s previous comments submitted on November 16, 2021), further revised to incorporate the change described above in Attachment A. These and other proposed revisions discussed in this document are marked with grey highlighting or with a comment that is highlighted in gray to differentiate these changes from the previous version of this document.

In addition, LUMA submits that, similar to the case of the TIR document, the Generator Interconnection Application and the Simplified Interconnection Application and Agreement forms should be flexible documents that can be revised or updated to adapt to changing circumstances, including changes in applicable laws and regulations and technical standards, without the need to amend the Interconnection Regulation. LUMA therefore proposes that the Generator Interconnection Application in Attachment 1 to the Draft Interconnection Regulation and the Simplified Interconnection Application and Agreement in Attachment 2 to the Draft Interconnection Regulation be removed from the Draft Interconnection Regulation and incorporated into the Draft Comprehensive TIR. Language has been added in relevant parts of the Draft Interconnection Regulation to clarify that these forms will be included in the TIR, and these changes are also marked in the revised Draft Interconnection Regulation attached as Exhibit B.

The mentioned forms have also been included in the revised Draft Comprehensive TIR document as Appendices I and J. Adding these forms to the TIR will also allow for revisions from time to time to the costs and deposit payments discussed above subject to the Energy Bureau’s approval.

3.0 Costs of Supplemental Study and Other Studies

Section 1.29(D) of the Draft Interconnection Regulation provides that the Electric Power System (EPS) Operator (under certain specified circumstances) shall “[o]ffer to perform a supplemental review in accordance with Section 1.30 and provide a non-binding good faith estimate of the costs of such review”. Similarly, Section 1.30 (A) provides that “[t]o 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 […]” while Section 1.30(B) provides that “[t]he 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 […]”

LUMA agrees with the approach in the Draft Interconnection Regulation that the Interconnection Customer be required to pay the actual costs for these studies and proposes no change to this language. LUMA would like to add clarity with respect to the costs of other studies discussed in the Draft Interconnection Regulation- generally consistent with the above, but with additional provisions.

Specifically, Section 1.34(C) of the Draft Interconnection Regulation provides that the EPS Operator is to provide a non-binding good faith estimate of the system impact study and the Interconnection Customer must make a deposit of the good faith estimated costs; however, this provision does not expressly indicate that the Interconnection Customer will be responsible for the actual costs of this study. LUMA therefore proposes that language be included to clarify that the Interconnection Customer is responsible for the actual costs of this study. Given the potential considerable costs of these studies and LUMA's budgetary limitations, LUMA also proposes that LUMA be provided the option of charging for the costs of these studies upfront. To incorporate this change, this provision would be revised to include the following language: "The EPS Operator may require the Interconnection Customer to make a deposit or an upfront full payment of the good faith estimated costs of the study, which deposit or upfront payment shall be provided by the Interconnection Customer when it returns the EPS Operator the System Impact Study Agreement executed by the Customer, and a true up cost will be done when the study is completed and delivered to the Interconnection Customer. The Interconnection Customer will be responsible for the actual costs of the study". This change is included in the Draft Interconnection Regulation attached as Exhibit B. Other conforming changes are included in the attached Draft Interconnection Regulation.

LUMA also proposes to include the same proposed text regarding the costs of the Transmission System impact study discussed in Section 1.34(F), the costs of which are not addressed in the Draft Interconnection Regulation. To incorporate this change, this provision would be revised to include the following: "The Interconnection Customer will be responsible for the actual costs of this study. The EPS Operator may require the Interconnection Customer to make a deposit or an upfront full payment of the good faith estimated costs of the study, which deposit or upfront payment shall be provided by the Interconnection Customer when it returns to the EPS Operator the Transmission System Impact Study Agreement executed by Customer, and a true up cost will be done when the study is completed and delivered to the Interconnection Customer." This change is included in the Draft Interconnection Regulation attached as Exhibit B. Other conforming changes are included in the attached Draft Interconnection Regulation.

As for the Facilities Study, Section 1.35 of the Draft Interconnection Regulation contains similar language on the costs of this study to that of the System Impact Study. LUMA therefore proposes that language be included to clarify that the Interconnection Customer is responsible for the actual costs of this study. In addition, given the potential considerable costs of these studies and LUMA budgetary constraints, LUMA also proposes that it be provided the option of charging for the costs of the study upfront. This proposed change would be included in Section 1.35 (B) where the following text would be added: "The EPS Operator may require the Interconnection Customer to make a deposit or an upfront full payment of the good faith estimated costs of the study, which deposit or upfront payment shall be provided by the Interconnection Customer when it returns to the EPS Operator the Transmission System Impact Study Agreement executed by Customer, and a true up cost will be done when the study is completed and delivered to the Interconnection Customer. The Interconnection Customer will be responsible for the actual costs of this study." This change is included in the Draft Interconnection Regulation attached as Exhibit B. Other conforming changes are included in the attached Draft Interconnection Regulation.

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4.0 Capacity Cap

After further evaluation, LUMA does not have comments regarding potential aggregated DG capacity caps per feeder. In light of current levels of DG integration and lack of information on the technology that could be applied to impose a capacity cap, LUMA is unable to provide concrete proposals at this time but may revisit this subject in the future.

5.0 Forms & Agreements - Other Clarifications

After having conducted this additional exercise of reviewing the Draft Interconnection Regulation and for the same reasons provided with respect to the Attachments 1 and 2, LUMA proposes that the forms of the Feasibility Study Agreement, System Impact Study Agreement, Facilities Study Agreement, Interconnection Agreement, and Agreement for Participation in the Shared Net Metering Program, included or intended to be included in Attachments 5, 6, 7, 8, and 9 of the Interconnection Regulation, respectively, removed from the Draft Interconnection Regulation document and be incorporated into the TIR document. LUMA understands that the forms for the System Impact Study Agreement and the Facilities Study Agreement should be used in both cases of transmission or distribution system impacts. LUMA submits that, similar to the case of the TIR document, all of these agreement forms should be flexible documents that can be revised or updated to adapt to changing circumstances, including changes in applicable laws and regulations and technical standards, without the need to amend the Interconnection Regulation. To implement this proposal, language has been added in relevant parts of the Draft Interconnection Regulation to clarify that these forms will be included in the TIR (with the clarifications indicated below), and these changes are also marked in the revised Draft Interconnection Regulation attached as Exhibit B.

The mentioned forms have also been included in the revised Draft Comprehensive TIR document (Exhibit A) as the following Appendices of this document:

Appendix L: Feasibility Study Agreement

Appendix M: System Impact Study Agreement (to be used for both Transmission and Distribution System impacts)

Appendix N: Facilities Study Agreement (to be used for both Transmission and Distribution System impacts)

Appendix O: Interconnection Agreement

Appendix P: Agreement for Participation in the Shared Net Metering Program

In the November15, 2021 comments, LUMA also recommended that the Certification of Generator Equipment Packages in Attachment 4 of the Draft Interconnection Regulation be addressed in the TIR instead. Accordingly, we have marked this change in the attached Draft Interconnection Regulation (Exhibit B) and incorporated this Attachment as Appendix K of the Draft Comprehensive TIR document (Exhibit A).

LUMA also made some minor revisions and clarifications to the Draft Interconnection Regulation which are included as redline revisions or balloon comments in Exhibit B, to address previous comments or correct inconsistencies.

Exhibit A

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Technical Interconnection Requirements

NEPR-MI-2019-0009

Last Updated: ~~May 19~~November 1, 2022

Style Definition: Heading 1: Outline numbered + Level: 1 + Numbering Style: 1, 2, 3, … + Start at: 1 + Alignment: Left + Aligned at: 0" + Indent at: 0.25"

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Table of Contents

~~1.~~0. Introduction

This Technical Interconnection Requirements (TIR) document provides guidance for Grid Interconnection and Parallel Operation with the Electric Power System (EPS). It provides criteria for EPS Operator's engineers, as well as Customers, Distributed Energy Resources (DER) Owners and DER Developers planning to interconnect 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 System connections are covered. Specific Transmission System and sub-transmission requirements are found in the Transmission and Sub-transmission section of this TIR.

The TIR would remain a separate document from the Interconnection Regulation and be subject to revisions from time to time to address changes, revisions or updates to applicable technical codes and standards, changes in technologies, and other changes in circumstances that would warrant revising or updating the document. These changes, revisions or updates would be subject to the Energy Bureau's review and approval as established in the Interconnection Regulation.

1.1. Scope

The requirements in this document apply to all aspects of DER connection and operation with the Grid. The table below outlines the applicable capacity and eligibility for Net Energy Metering (NEM) for each system category covered in this TIR document and shows the TIR section numbers associated with each category.

System	Capacity	Eligible for NEM	TIR Section #
Distribution	Up to 25 kW for Solar	Yes	1-12
	Up to 50 kW Solar + BESS	Yes	1-12
Distribution	up to 1 MW	Yes	1-13
Distribution – Microgid	up to 5 MW	Yes	14
Transmission/Sub-Transmission – Microgrid	up to 5 MW	Yes	14
Sub-Transmission	up to 5 MW	Yes	15.2
Transmission	up to 5 MW	Yes	15.2

Although this TIR document covers, technically speaking, renewable resources' capacity above 5MW as well, from the procedural perspective however this TIR document does not cover any size renewable resources that are included in the Case No. NEPR-MI-2020-0012, such as generation resources above 5MW which intend to export energy into the system. In such case, these resources must comply with the Minimum Technical Requirements (MTRs) for utility scale projects as required in the PREB Renewable Integration Process Case No. NEPR-MI-2020-0012.

The document addresses the 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 System.

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 but not limited to, IEEE Standard 1547™, the National Electrical Code, other safety codes, and all applicable laws, statutes, guidelines, and regulations. The foregoing includes installing, setting, and maintaining all protective devices necessary for safe grid integration and to protect the IC's and the EPS facilities.

Terms and acronyms used in this document, not otherwise defined in Section 2.1 of this TIR document, are to be interpreted as defined in IEEE Std 1547-2018, and other related IEEE, IEC, and ANSI standards, etc. The reader is advised to reference the standard since it is integral to understanding the requirements of this document.

1.2.2. EPS Operator Managed and Operated Distribution System

Requirements specified in the TIR Document are also intended to complement EPS Operator efforts and responsibility to maintain the Transmission and Distribution Systems Grid safety, power quality and reliability. Continuity and quality of service to all Customers is a key responsibility of EPS Operator.

1.2.3. Requirements Related to Ongoing EPS Upgrades

The EPS reconfigures circuits occasionally to accommodate new load and to improve reliability and efficiency. The possibility exists that a change in the EPS may cause a change in the protection or other requirements at the DER interconnection. It would then be the responsibility of the DER Owner to make the necessary changes to meet these changing Grid requirements.

1.2.4. Network Upgrades

The DER Owner, DER Developer or Customer is responsible for any needed electric system upgrades and any analysis, engineering, and design work to accommodate their Interconnection and comply with this TIR document.

1.2.5. Disconnect from EPS

All DERs that intend to Operate in Parallel with the EPS must be considered under one of the agreed procedures set forth in the Interconnection Regulation, regardless of whether they will export energy to the Grid. If the EPS finds a DER Operating in

Parallel without proper approval process or, in violation of law or applicable regulations, the EPS reserves the right to disconnect the DER from the Grid due to security and safety reasons.

~~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 (Interconnection Regulation).

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

- ***Abnormal Conditions*** *– Any abnormal condition of the electrical system that involves the electrical failure of equipment or lines.*

- ***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.*

- ***Active Power*** *– The real power consumed in an electrical circuit. It is the useful power which may be termed true or real power and measured in terms of Watts, Kilo Watts or Mega Watts.*

- ***Advanced Metering Infrastructure*** *– (AMI) refers to systems that measure, collect and analyze energy usage, and communicate with Metering devices such as the electricity Meter either on request or on a schedule.*

- ***Advanced Distribution Management System (ADMS)*** *-- The software platform that supports the full suite of distribution management and optimization. An ADMS includes functions that automate outage restoration and optimize the performance of the distribution Grid.*

- ***AMI Voltage*** *– Voltage measurements at the Meter coming from the AMI system.*

- ***Automatic Circuit Recloser (ACR)*** *– An automatic, high-voltage electric switch that can be used to isolate faults and reconfigure the system.*

- ***Area EPS*** *– Means company EPS, Electrical Power System that serves Local EPS.*

- ***Basic Insulation Levels (BIL)*** *– A design voltage level for electrical apparatus that refers to a short duration (1.2 x 50 microsecond) crest voltage and is used to measure the ability of an insulation system to withstand high Surge voltage.*
- ***Battery Energy Storage Systems (BESS)*** *– An electrochemical device that charges (or collects energy) from the Grid or a Generating Facility and then discharges that energy at a later time to provide electricity or other Grid services when needed.*

- ***Buffers****– Are limits, defined and used to protect the Grid by providing a safety margin added to DER integration limits; for example, it provides limits to prevent reverse power on a substation power transformer.*

- ***Cogeneration Facility*** *– Cogeneration or Cogen, or Combined Heat and Power*

(CHP) is the use of a heat engine or power station to generate electricity and useful heat at the same time.

- ***Company*** *–* ***LUMA ENERGY SERVCO, LLC****, a limited liability company organized under the laws of the Commonwealth of Puerto Rico (****LUMA*** *or* ***EPS 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.*

- ***Constant Power Factor*** *– A DER maintaining the same Power Factor over different operating output levels, is said to maintain a Constant Power Factor.*

- ***Constant Reactive Power Mode*** *– A DER set to inject or absorb a certain amount of Reactive Power.*

- ***Combined Heat and Power (CHP)*** *– See Cogeneration or Cogen facility.*

- ***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.*

- ***Current Transformer (CT)*** *– A type of transformer used to reduce or multiply an alternate current (AC). In its secondary side it produces a current proportional to the current in its primary side.*

- ***Customer*** *– Any natural or legal person who requests, contracts and obtains electric power service, which continues to be supplied, as long as he does not formalize a request to cancel the service and provides access to disconnect it. This term also includes the Interconnection Customer. The Customer may appoint a representative to process the technical aspects under this TIR with the EPS Operator, but it will always be the one who will contract with the EPS Operator and will be responsible to it.*

- ***DC Injection*** *– The injection of direct current into the Grid which is based on alternating current.*

- ***Dedicated Circuit*** *– A feeder circuit that is added for only one entity and no other entities connect to that circuit. This may be required for extremely critical load or in cases where the protection scheme may only be able to accommodate the single Customer.*

- ***Dedicated Transformer*** *– EPS Operator may require for the Generating Facility within a Customer Microgrid to install a dedicated transformer, where the Generating Facility is served from the same transformer secondary as another Customer and if the DER is inverter-based with Grid forming capability.*

- ***Department of Economic Development and Commerce (DEDC)*** *– A government body of the executive branch of the Government of Puerto Rico created by the Department of Economic Development and Commerce Reorganization Plan of 1994, Plan No. 4 of June 22, 1994, as amended, and pursuant to the Department of Economic Development and Commerce Reorganization Plan Implementation Act of 2018, Act No. 141 of July 11, 2018, or the successor government entity thereof established by law.*

- ***DER Facility or DER System*** *– 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.*

- ***DER Mode*** *– Typically a setting on voltage regulators so they will continue to correctly regulate voltage even if a DER causes reverse power to occur. Also referred to as DG mode or Cogen mode.*

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

- ***Developer*** *– An entity that may design, install, and possibly operate a DER for the Customer.*

- ***Direct Transfer Trip (DTT)*** *– Remote operation of a circuit breaker by means of a communication channel. Utility protection devices can trip a DER when certain events necessitate the disconnection of the DER.*

- ***Distribution Automation (DA)*** *– Is a family of technologies, including sensors, processors, information and communication networks, and switches, through which a utility can collect, automate, analyze, and optimize data to improve the operational efficiency of its distribution power system. It provides the logic for isolating faults and restoring power to non-faulted sections of a feeder.*

- ***Distribution System or Network*** *– The physical equipment of the EPS 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)*** *– Is distributed generation sources or storage that is either connected to the Distribution or Transmission System and are usually small capacity (less than 10 MW) and modular in nature. DER as used in this report includes distributed generation, distributed energy storage, energy efficiency, demand response and electric vehicles. It can also be referenced as DER Unit, DER System or DER facility.*

- ***Dynamic VAR Compensation*** *– Fast acting Reactive Power compensation used to help control voltage and system stability especially during transient disturbances such as generator or transmission line trips, major faults or other system conditions needing VAR support.*

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

- ***Electric Power System Operator*** *or* ***EPS Operator*** *– The entity that controls or operates the Electric Power System.*

- ***Electromagnetic Interference (EMI)*** *– Unwanted noise or interference in an electrical path or circuit caused by an outside source. It is also known as radio frequency interference. EMI can cause electronics to operate poorly, malfunction or stop working completely.*

- ***Emergency Conditions*** *– Abnormal Conditions of the electrical system that can require significant intervention by the EPS Operator including the possible tripping* *of DERs or asking that they operate in a certain way.*

Energy Bureau *– The Puerto Rico Energy Bureau (PREB), 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, is a specialized independent entity in charge of regulating, overseeing, and enforcing the public policy on energy of the Government of Puerto Rico.*

- ***Energy Storage System (ESS)*** – A *device or group of devices assembled that is to convert the electrical energy from power systems and store energy in order to supply electrical energy at a later time when needed.*
- ***Express Circuit*** *– A feeder circuit added to service a new load or DER. The EPS Operator may connect future load or DER Customers as long as the required capacity and reliability is maintained to the original facility. For instance, if an Express Circuit only has a wholesale solar DER facility, and a load Customer is added, it will, in general, improve the efficiency.*
- ***Express 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).*
- ***Fast Frequency Response*** *– Refers to the delivery of rapid Active Power increase or decrease by generation or load in a timeframe of 2 seconds or less, to correct a supply*
  – demand imbalance and assist in managing power system frequency.
- ***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.*
- ***Flicker Capacity*** *– The capacity of a circuit to withstand rapid changes in voltage.*
- ***Flicker Limit*** *– Limit in the amount of flicker that a DER may cause on a circuit.*
- ***Frequency Droop*** *– In droop mode, a generator's output and frequency are inversely proportional. When frequency decreases, output increases.*
- ***Frequency Trip*** *– The frequency at which a DER will trip offline - either too high or too low after the Ride Through period.*
- ***Generator Fault Contribution*** *– The amount of current a Generating Facility will contribute when a fault occurs on the Grid it is connected to.*
- ***Grid*** *– The interconnected arrangement of lines, transformers and generators that make up the EPS.*
- ***Grid Connected Mode, Grid Connected or Grid Connected Operation (GCM)*** – T*his is also called blue sky mode, when Microgrid is connected to Grid and exchanges power (Active and Reactive Power) with the rest of the Area EPS*

- ***Grid Forming DER*** *– A term for defining a DER with capability of actively regulating its voltage and power frequency at PoC, in response to power exchange level (loading). A Grid Forming DER can operate independent from an EPS (off-the-Grid), while maintaining nominal voltage and frequency required for serving Customer loads, or it can Operate In Parallel with an EPS by adjusting Active and Reactive Power output to stay in synchronization with the grid. There should be at least one Grid Forming DER in a Microgrid that can Island. Synchronous Generators and Energy Storage Systems are examples of DER with grid forming capability.*

- ***Grid Support Interactive Inverter*** *– State of the art technology that converts DC power to AC power with the inherent ability to synchronize with the Grid and provide support in the way of absorbing or injecting Reactive Power and by possibly curtailing real power if needed.*

- ***Grid Support Utility Interactive Inverter*** *– Same as Grid Support Interactive Inverter but may include utility communication and control.*

- ***High Voltage Ride Through (HVRT)*** *– The ability of a DER to Ride Through for designated periods of time, abnormally high voltage.*

- ***Host Load*** *– The electrical power, less the Generator Auxiliary Load, consumed by the Customer, to which the Generating Facility is connected.*

- ***Hot Stick Test*** *– Using an insulated pole, usually made of fiberglass, electric utility workers when working on energized high-voltage electric power lines, can test for voltage and current.*

- ***Islanded Mode of Operation, Islanded Operation, Island, Islanded, or Islanding (IMO)*** *– This is one of the operating modes of the Microgrid in which the Microgrid boundary is separated from the Area EPS (EPS Operator Distribution systems) and is solely powered up by the Customer owned DER units within that Microgrid.*

- ***Inadvertent Energization*** *– Energization during a period of time the DER should not be energized.*

- ***Induction Generators*** *– An asynchronous generator that is a type of alternating current (AC) electrical generator using the principles of induction motors to produce electric power. Induction Generators operate by mechanically turning their rotors faster than synchronous speed.*

- ***Instrument Transformers*** *– A transformer (*current transformers and potential transformers) *that is used to measure electrical quantities such as current, voltage, power, frequency, and Power Factor. These transformers are mainly used with relays to protect the EPS.*

- ***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 between the Interconnection Customer and the EPS as defined in the 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 or Interconnecting Customer (IC)*** *-- Customer with a DER that Operates in Parallel with the Grid. It is the Account holder with the EPS Operator that complies with all the provisions of the Interconnection Agreement and this TIR and is responsible for the Interconnection of its Generating Facility with the EPS. The IC may appoint a representative to process the technical aspects under this TIR with the EPS Operator, but the IC will always be the one who will contract with the EPS Operator and will be responsible to it.*

- ***Interconnection Equipment*** *– The equipment necessary to safely Interconnect the DER 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 Regulation*** *– The Puerto Rico Energy Bureau's Generating Facility and Microgrid Interconnection Regulation then in effect.*

- ***Interconnection Study*** *– A technical study or studies performed to identify actions required to allow a 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.*

- ***Load Tap Change (LTC)*** *– See On Load Tap Changer (OLTC).*

- ***Local EPS*** *– Facilities that deliver electric power to a load that is contained entirely within a single premise or group of premises.* .

- ***Low Voltage Alternating Current (LVAC)*** *– Generally distinguishes between Primary or Feeder Circuit Voltages and the secondary or Low Voltage.*

- ***Low Voltage Ride Through (LVRT)*** *– The ability of DERs to remain in service during a voltage dip caused by a fault or disturbance.*

- ***Meter*** *or* ***Metering*** *– 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.*

- ***Microgrid*** *– 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 Facilities. In some cases, the EPS Operator's Facilities may also be included in the Microgrid.*

  According to Regulation 9028[1], three Customer-owned Microgrid types are defined: Personal, Cooperative, Third-Party. For this technical requirement document, all three types are equally referred to as Customer-Microgrid.

  - ***Personal Microgrid****: is a Microgrid type that provide power to one or two consumers only and can, with PREB permission, provide excess energy and grid services to neighboring Customers. It should be noted that energy produced by this type of Microgrid is primarily for the consumption of its owner and could be behind or in front of a Meter.*

  - ***Cooperative Microgrid****: is a Microgrid type that serves three or more cooperative members, under two subcategories: a) Small co-op Microgrids with generating capacity of less than 250 kW, b) Large co-op microgrids with generating capacity of more than 250 kW. Similar to personal Microgrids, Cooperative Microgrids can sell excess energy and services to others, with PREB permission.*

  - ***Third-party Microgrid****: is a Microgrid type that have owners or operators with the primary purpose of engaging in the sale of energy services and other grid services to the Customers under rates approved by PREB.*

  - ***Mixed-ownership Microgrids*** *– Any Microgrid that utilizes both Customer owned assets and EPS assets are called mixed-ownership Microgrids. In this case, Customer owns most of the Microgrid assets, specifically the DERs and interconnection switchgears associated with them. Parts of the right of way, wires/lines, poles, services transformers, or any other switchgear that may be required for transferring power to the Microgrid Customers may be part of the EPS. Additional studies and engineering related to the IMO of Microgrid are required to full fill the technical requirements of mixed ownership.*

- ***Microgrid Controller*** *– The Microgrid Controller (MGC) is an intelligent system designed to manage and automate the operation of the Microgrid system.*

- ***Microgrid Interconnection Devices (MID)*** *– A device installed by Customer at the Microgrid Interconnection point that allows the Microgrid to separate from the EPS* Operator*'s system (for islanded operation) or reconnect to the EPS (Parallel Operation).*
  - *MID could be a recloser, a circuit breaker, or a disconnect switch.*
  - *MID shall have synchronization capability, if a live reconnection of the*

[1] Puerto Rico Energy Bureau, Regulation on Microgrid development – Number 9028

Microgrid to EPS is desired (make-before-break).
- *It should be noted that, in addition to MID (at PCC), the Customer shall install a visible isolation device at each DER location or at the PoC of the Generation Facility within the Microgrid (for multiple DERs in one location), if MID is not recognized as the main visible disconnect switch for the Microgrid due to inclusion of loads inside a Microgrid boundary.*

- ***Microgrid Operator** – Legal or natural person who is the registered operator of a Microgrid, which is the primary party responsible for overseeing the operation of the Microgrid equipment, providing maintenance, delivering contracted services, billing for such services, and serving as the primary point of contact. The Microgrid Operator may or may not be the owner of the Microgrid.*

- ***Nationally Recognized Testing Laboratory (NRTL)** – A qualified private organization recognized by the Occupational Safety and Health Administration to perform independent safety testing and product certification.*

- ***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.*

- ***Network Service** – The provision of service connecting a Customer to the EPS which is a network of electrical components deployed to supply, transfer, and use electric power.*

- ***On Load Tap Changer (OLTC)** – Also referred to as an Under Load Tap Changer or just Load Tap Changer, this mechanism adjusts the turns ratio on a substation power transformer to maintain proper secondary voltage during changes in load level or variations in the source voltage.*

- ***Operator-In-Charge (OIC)** – A person or persons on site that is directly responsible for a plant or Distribution System*.

- ***Over Excited** – When Reactive Power is flowing from the Generating facility to the Grid.*

- ***Owner** – Legal or natural person who has property rights to a Generating Facility or associated infrastructure, including Interconnection infrastructure.*

- ***Paralleling Device** – A combination of protection, Metering, control and switching elements acting as an integrated system to allow an operating DER to seamlessly connect to Grid – insuring proper synchronization.*

- ***Parallel Operation or Operation/Operate/Operating in Parallel or Paralleling** – 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.*

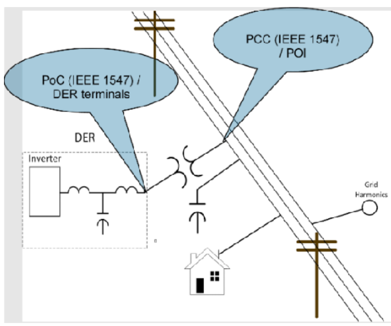
- ***Plant** – One or more DERs which are producing electric power.*

- ***Plant Capability** – The maximum sustained output the plant is capable of* *generating at the then current ambient conditions consistent with Prudent Generator Practices when operating on the designated fuel source.*

- ***Power Factor (PF)*** *– Power factor is the relationship (phase) of current and voltage in AC electrical distribution systems. Under ideal conditions current and voltage are "in phase" and the Power Factor is "100%."*

- ***Potential Transformer (PT) or Voltage Transformer (VT)*** *– A transformer designed to present a negligible load to the supply being measured and have an accurate voltage ratio and phase relationship to enable precise secondary connected metering.*

- ***Point of Common Coupling (PCC)*** *– The point where EPS service connects with the DER or a Customer Microgrid. This is usually called the Point of Interconnection (POI) when involving multiple DER or a Microgrid that uses mixed ownership (includes EPS assets). (Adapted from IEEE Std 1547™-2018.)*



- ***Point of Connection (PoC)*** *– The point where the DER is connected to the Electric Power System. (Excerpted from IEEE Std 1547™-2018.)*

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

- ***Power Delivery System*** *– See EPS definition.*

- ***Power Export Limit*** *– The maximum power level that can be safely and reliably exported to the Grid at a given time and particular Grid condition.*

- ***Protective Relays*** *– A relay device designed to trip a circuit breaker when a fault is detected*

  .

- ***Public Energy Policy Program (PEPP) –*** *Office of the Department of Economic Development and Commerce that oversees developing and promulgating the energy public policy of the Government of Puerto Rico, by virtue of Act No. 141 of July 11, 2018, also known as the Department of Economic Development and Commerce Reorganization Plan Implementation Act of 2018.*

- ***PV*** *– Photovoltaic system, used to convert light energy into DC power.*

- ***Rapid Voltage Change (RVC)*** *– A fast rise or fall of the RMS voltage. This can be caused by the switching on of a specific load or by a sudden change in source voltage. Sudden source voltage changes can occur in solar grids when the sun is obscured by clouds.*

- ***Rate of Change of Frequency (ROCOF)*** *– The time derivative of the power system frequency (df/dt).*

- ***Reactive Power*** *– Reactive power is either generated or absorbed by electric generators and loads. In some cases, devices known as "capacitors" are used to provide Reactive Power to improve the Power Factor of a circuit.*

- ***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.)*

- ***Ride Through*** *– Means that the DER must stay online and operate as specified during voltage or frequency disturbances caused by such things as faults, trips or switching events on the Transmission or Distribution System.*

- ***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. The unit communicates with a master unit at the Control Center.*

- ***SCADA*** *– An acronym for Supervisory Control and Data Acquisition. SCADA generally refers to an industrial computer system that monitors and controls a process. In the case of the transmission and distribution elements of electrical utilities, SCADA will monitor substations, transformers, and other electrical assets.*

- ***Short Term Flicker Perceptibility (Pst)*** *– Is the measure over a short period (a few minutes) of how irritating flicker is thought to be.*

- ***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).

- ***Standby Service Rate*** *– A rate for providing back up power delivery service.*

- ***Surge*** *– A transient wave of current, voltage or power in an electric circuit with a very short duration.*

- ***Surge Withstand*** *– A measure of an electrical device's ability to withstand high-voltage or high-frequency transients of short duration without damage.*

- ***Synchronous Generator*** *– A synchronous machine which converts mechanical power into AC electric power through the process of electromagnetic induction. Synchronous Generators are also referred to as alternators or AC generators.*

- ***System Emergency*** *-- An imminent or occurring condition on the EPS, or in a Generating 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.*

- ***Technical Interconnection Requirements (TIR)*** *– EPS Operator's requirements for the safe, orderly, and reliable Interconnection of DERs to the Grid.*

- ***Technical Interconnection Standards*** *– Standards that dictate how renewable DERs can be legally connected to the Grid. They are a set of requirements and procedures for both the EPS and Customers including the Interconnection Regulation, the Interconnection Regulation, other applicable Energy Bureau regulations and other technical codes and standards*.

- ***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 electrical parameters or related utility equipment condition status.*

- ***The Institute of Electrical and Electronic Engineers (IEEE)*** *-- IEEE is a nonprofit, global organization of professionals founded in 1963. It works solely toward innovating, educating, and standardizing the electrical and electronic development industry. It is best known for its development of standards such as IEEE 1547.*

- ***Total Fault Current Available*** *– The amount of available fault current during a short- circuit which depends on factors such as the generation source, length and size of the conductor supplying the faulted circuit and other factors affecting impedance.*

- ***Total Rated Current (TRD)*** *– The upper limit on how much current can flow from the DER.*

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

- ***Under Excited*** *– When Reactive Power is flowing from the Grid (source) to the Generating Facility.*

- ***Underwriters Laboratories (UL)*** *– Is a global safety science company and the largest and oldest independent testing laboratory in the United States.*

- ***VAR*** *– VAR stands for Volt-Amps Reactive and is the measuring unit for Reactive Power, which is created by energizing transformers and powering motors, pumps, air conditioners, and other similar devices.*

- ***Voltage Control*** *- Means keeping network voltages within operational limits in normal operation and in the aftermath of trips by automatic regulation of generation MVA output or by transmission voltage control equipment such as capacitor banks and automatic tap-changers.*

- ***Voltage Fluctuation*** *– A voltage fluctuation is a regular change in voltage that happens when devices or equipment requiring a higher load are used.*

- ***Voltage Regulation*** *– The maintenance of a voltage level between two* *established set points, compensating for transformer and/or line voltage deviation, caused by load or other system conditions.*

- ***Voltage Trip*** *– A power trip when the power falls below a preset level, usually between 70 and 35 percent of the under-voltage rating.*
- ***Volt/VAR Control*** *– A common control function for DER power converters that is used to enhance the stability and reliability of the voltage in the distribution system.*
- ***Witness Testing, Witness Test, or Witness the Testing*** *– Verification by EPS Operator's personnel that the DER and related protective equipment are built to specification, set correctly, and operate properly.*

~~3.~~2. General Review Requirements

Criteria for DER Interconnection

All DER Interconnections will be evaluated following the principles of these Technical Interconnection Requirements, which are:

- DER Interconnection and operation shall not compromise the safety of the public or EPS Operator's 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 EPS Operator's direction during Emergency Conditions or System Emergencies, or to requests to remove the DER from service when EPS Operator 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 Interconnection Customer, DER Owner, Developer or DER operator as mandated by applicable tariffs or rules. DER Interconnection should not increase Customer rates.
- The costs and benefits of the Interconnection of a DER ought to be considered as a function of the benefit it will provide in reaching renewable energy goals set by law.

All Interconnection Customers, DER Owners, Developers and DER operators of approved DER Interconnections are required to be responsive to EPS Operator's direction and instructions during normal and Emergency Conditions or System Emergencies, or to remove the DER from service when EPS Operator is performing line maintenance or other work on the circuit to which the DER is connected.

Application Technical Review Process

Guidelines for processing applications to Interconnect DER and the related technical reviews are specified by the Interconnection Regulation. Details of the process depend on the complexity of the DER to be connected. The Interconnection Regulation provides different DER application levels, which are defined by voltage level, 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 Grid are subject to technical review. Links to Interconnection Application processing are as follows:

- Interconnection 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 this Technical Interconnection Requirements (TIR) document and Technical Interconnection Standards, including the Interconnection Regulation, other applicable Energy Bureau regulations and other technical codes and standards, and does not adversely impact other Customers. Interconnection Forms and Agreements are listed in Section 16.

Applicability

This TIR document applies to DERs of up to 1MW Interconnected with the Distribution System and DERs of up to 5MW Interconnected to the Transmission System and sub transmission system. Units larger than these limits will require additional studies and may be subjected to more stringent requirements than those presented in the respective sections of this document. These larger Interconnection Application may result in more extensive system upgrades.

~~4.~~3. DER Technologies

This Section, in conjunction with Section 14, covers the entirety of the resources that can Interconnect to EPS. All equipment that forms part of a Generating Facility system based on renewable energy sources must be approved/certified by the PEPP 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 Interconnection Regulation.

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." All new solar connections will need to be supported with a commissioning sheet that provides evidence the inverter has been installed and programmed in compliance with Appendix I: Generator Interconnection Application

(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 Generating Facility or 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 Generating Facility or 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: _________________________________

Microgrid Information:

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).

*Aggregate Generator Nameplate kV*AR: _______________.

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.

Generating Facility Characteristic Data (for inverter-based machines)

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.

  - 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 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

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: ___________

. The evidence must be in the form of screen print or manufacturer's certification of inverter settings being in compliance with the Smart Inverter Setting Sheets (Appendix H).

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

The EPS Operator reserves the right to require smart inverter interface where needed following the EPS proposed smart inverter setting sheet 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.

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~~enabled as specified by the smart Inverter Setting Sheets as defined in Appendix H.

~~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, EPS Operator may need to control the DER through communication devices. This includes communication interoperability that may be used to update specific functions and settings.

Inverter operational requirements may include:

- To address steady state high voltage on the circuit due to output from a DER, EPS Operator may require the DER to reduce power output when Grid voltage goes above ANSI limits.
- Where an ACR has been installed, EPS Operator 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.

EPS Operator will only allow the use of equipment with inverter technology, generators, relays and other devices that comply with applicable standards and codes. These must be evaluated and approved by EPS Operator. EPS Operator has a list of approved inverters and control systems

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periodically updated, which is made available on the DER Portal website. If the equipment has not been evaluated and approved by EPS Operator, the EPS Operator may request that the manufacturer, distributor, or Interconnection Customer, DER Owner or DER Developer send to 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 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 fields such as frequency, voltage and operating times.

Renewable Resources

All equipment that forms part of a Generating Facility system based on renewable energy sources must be approved/certified by the PEPP 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).

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.

Battery Storage

Evaluation of DER Battery Energy Storage Systems (BESS) 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.

Induction Generators

Customers shall be required to install mitigating equipment in cases where Induction Generators for intermittent sources cause voltage or reactive current issues. Generating facility 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.~~4. 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	Applicable with any exceptions called out in this document
Cease to Energize	4.5	Always
Control Capability Requirements	4.6	Always
Prioritization of DER Responses	4.7	Always
Isolation Device	4.8	Systems >300kVA
Inadvertent Energization of Area EPS	4.9	Always
Enter Service	4.10	DER <250kVA
DER Interconnection integrity	4.11	Always
Effective Grounding	4.12	Always
Reactive Power capability	5.1, 5.2	Applicable except where superseded by Regulation or TIR requirements
Reactive Power control	5.3	Applicable except where superseded by Regulation or TIR requirements
Active Power control	5.4	Applicable except where superseded by Regulation or TIR requirements
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	PR settings (unless adopting Category III default)
Limits on DER DC injection	7.1	Always
Limits on DER-caused voltage fluctuations	7.2	Always

Limits on harmonic distortion	7.3	Always
Limits on transient overvoltage from DER	7.4	Always
Unintended Islanding detection	8.1	Always
Plant Interoperability	10	Always
Plant commissioning tests	11	Always

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.

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. The applicable voltages that shall be detected are shown in Table 5-2.

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)

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 5-3. For multi-phase systems, the requirements for applicable voltages shall apply to all phases.

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 Zigzag	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 EPS 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 114V-126V at the Meter.

Existing Service Transformer Connections

Low voltage DER connections are normally via an existing EPS load service transformer. Larger Generating Facilities may require either an upgrade of the service transformer, the addition of a DER plant service transformer, connect to a distribution system or an express distribution feeder or other infrastructure.

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.

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 EPS 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 Customer/DER Owner/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 Customer, DER Owner or Developer shall be advised to use a transformer with no load taps (+/- 2.5 and 5% typically).

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.

Effective Grounding

The DER Interconnection (inclusive of DER assets and Interconnection 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 overvoltage's will not exceed the limits contained within 1547-2018. EPS Operator may require proof of meeting this requirement, in the form of an electromagnetic transient study to be conducted by the Customer/DER Owner/Developer.

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.

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.

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.

Isolation Device

Customers/DER Owners/Developers 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.

EPS Operator requires the installation of a EPS accessible 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 EPS Operator can access will be required. If remote trip or Direct Transfer Trip (DTT) are required, the isolating device shall be able to operate based on the respective signal.

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."

Enter Service

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.

DERs shall not energize the EPS until the applicable voltage is between 0.88 pu and 1.1 pu and the frequency is between 58.8 Hz and 61.2 Hz. Settings may include a delay to enter service of up to 300 seconds and a duration for entering service of 300 seconds applying a linear or stepwise linear ramp.

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.

DER Interconnection integrity

This Section addresses integrity 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 Grid and are covered in IEEE Std 1547™- 2018 section 4.11.

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.

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.

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.~~5. DER Support of Grid Voltage

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(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.

EPS Operator Requirements

- Inverter-connected DERs shall have Category B Reactive Power capability and will be set according to EPS Operator's 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 based on size and/or technology may be required to operate in one of several Reactive Power control modes as described in Section 6.3. 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 EPS Operator 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 IEEE Std 1547 are expected to meet at least Category B requirements.

Reactive Power Control

The DER shall be capable to provide voltage regulation by changes of Reactive Power. EPS Operator 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. EPS Operator will provide the proper settings.

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. EPS Operator will provide the proper settings.

~~7.~~6. DER Response to Abnormal Conditions

Events on the Grid such as an open phase or system fault, and the related actions by EPS Operator 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.

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.

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 (RPA). 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.

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.

Area EPS Reclosing Coordination

EPS Operator'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 Interconnection Customer's facilities, EPS Operator will require additional protective equipment be installed. For example, some DER configurations may require Direct Transfer Trip (DTT) of connected DERs for line faults. This will usually consist of communication and/or control equipment to disconnect the Interconnection 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 EPS Operator's reclosing scheme, consideration when entering service, and voltage Ride Through requirements for consecutive temporary voltage disturbances caused by reclosing sequence.

Voltage Trip and Ride Through Requirements

Manufacturer specifications for all voltage protection schemes must be submitted to EPS Operator 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, EPS Operator 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[2] for requiring Category I, II or III.

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. EPS Operator 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 EPS Operator 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, EPS Operator 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.

[2] LUMA will consider Annex B of IEEE 1547™-2018 when making these determinations on a case-by-case basis.

~~8.~~7. Protection Coordination Requirements

EPS Operator will determine the bus and line configurations and the protection requirements that are necessary to connect the DER proposed in the IC's Interconnection 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 C. 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.

Buffers Capacity

Buffers are set around specific DER integration requirements such as current levels, individual or aggregate DER capacity, and reverse power kVA limits. Buffers 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.

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.

EPS Operator will require the Customer/DER Owner/ Developer to identify and disclose the method of Islanding detection that is being used for all DERs above 25 kW. EPS Operator 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.

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 EPS Operator equipment serving the Generating Facility.
- Any synchronous 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.
- EPS Operator will consider all existing generation with and without DTT in the same zone of protection in the determination of a DTT requirement.

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.

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

Protective Relays (or built-in protection functions)

Interconnection configurations are site and feeder dependent. EPS Operator 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 C.

Review of Specifications

Manufacturer specifications for frequency and voltage protection schemes must be submitted to EPS Operator 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.

Telemetry

Telemetry shall be implemented for any DER larger than 1 MW AC as well as for any DER 250 kW AC or greater on a feeder that has or may have Distribution Automation. EPS Operator reserves the right to require Telemetry for smaller DER Interconnections as necessary for monitoring and control to maintain reliability.

EPS Operator 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 EPS Operator. The IC will be responsible for the installation cost and ongoing communication costs of the Generating Facility 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 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.

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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 Generating Facilities >1 MW.

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, EPS Operator will work with the Customer to establish a means of tripping the DER without loss of service to other loads.

Other Equipment and Protection Requirements

A DER may or may not be allowed to operate under alternate supply. This determination will be made by EPS Operator 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.

Facilities containing DERs greater than 500kW require a three-phase fault interrupter installed at the PCC to allow three-pole disconnection of the facility by the EPS in case of a Customer-side fault or mis operation.

~~9.~~8. 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.[3] 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, the EPS Operator requires DERs to be certified to meet this standard and any other limits within his Technical Interconnection Requirements.

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.

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. EPS Operator 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.

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.

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 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.

[3] Power system compatibility standards such as IEEE 519 (on harmonics), IEEE 1453 (on power fluctuations), and IEC 61000 series (on Electromagnetic Compatibility).

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.

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 ("TRD") distortion 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.

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/Customer's expense.

Cumulative instantaneous overvoltage shall be limited to the requirement found in 1547-2018.

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 EPS Operator 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:

$$\mathit{phase\ voltage\ unbalance}\ (\%) = 100 \cdot \frac{\max \mathit{deviation\ from\ average\ phase\ voltage}}{\mathit{average\ phase\ voltage}}$$

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, where V2 is the deviated voltage and V1 is the average phase. The first two definitions, if employed, will have a limit of 3%. The third definition, if employed, will have a limit of 2%. EPS Operator 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.

Grid Integration for Radial-Connected DER

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.

Aggregate and Individual DER Capacity Limits

The largest DER system on the Distribution System is limited to 1 MW AC. The limits mentioned in this section are application limits and do not imply the electric Grid can accommodate a particular application without significant modifications or upgrades.

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, 8.32 kV	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/DER Owner/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. EPS Operator 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 EPS Operator can mitigate voltage fluctuation or steady state voltage rise as penetration increases. If necessary, EPS Operator 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.

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 EPS Operator 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 stations, 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.

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.

DER Customers with Multiple Radial Services

EPS Operator will determine if a DER can operate under alternate supplies during the Interconnection assessment phase. EPS Operator 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 (DTT) 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 EPS Operator 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 EPS Operator 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 EPS Operator operational requirements.

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.

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.

Load Transfers

Interconnection of large DERs may prompt a study to determine if there are issues for any EPS Operator 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

General

Reverse power flows shall not be allowed through any electric system components not designed to accommodate it. Distribution System components that may not be designed to accommodate reverse power flow include:

- Voltage regulators,
- Distribution System power transformers,
- Circuit terminals,
- Substation metering.

For example, voltage regulators will not operate correctly under reverse power unless they are reversible and set for DER 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.

Reverse Power and Safety Buffers

Components not specifically designed to accommodate reverse power flow require operating Buffer- to ensure that periods of low load coinciding with periods of high DER generation do not result in reverse power. These Buffer- 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 System 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.

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 for equipment by circuit voltage level

Circuit Voltage Level	Minimum Size of Buffer (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 EPS Operator. 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 DER Mode or auto-source sensing,
- Transmission-level reverse power limitations,
- Need for 3V0 protection at sub, or power limits, and
- Transformer life/rating concerns.

Feeder Upgrade Options and Requirements

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 Customer/DER Owner/ 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.

Sub-Station Power Transformers

The following criteria shall apply where a DER Facility 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.

Feeder Voltage Regulators

Where a DER Interconnection requires a voltage regulator to be added or upgraded, this must be completed before approval to operate. EPS Operator will apply the following requirements if reverse power is possible:

- Upgrades will provide for bi-directional operation.
- Upgrades will include a DER 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 EPS Operator regulating equipment. If communication is required, voltage regulators shall be equipped with Telemetry to the Control 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.

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.
- EPS Operator will determine settings for switched capacitor banks in coordination with any DER Reactive Power response settings, during Interconnection technical review.

Circuit & Bus Reconfigurations

Circuit reconfigurations are not allowed to accommodate an Interconnection. From time to time, EPS Operator 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.~~9. Plant Interoperability

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 EPS Operator and clarifies which systems must be connected to telecommunications networks for data to be collected and/or exchanged.

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. EPS Operator 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.

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 EPS Operator.

A standardized, local DER communication interface makes it possible for EPS Operator (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.

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. EPS Operator 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 EPS Operator requires Telemetry on systems less than 250kW, output should be DNP3.

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, EPS Operator requires the unlock mechanism be implemented such that:

- EPS Operator 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 EPS Operator 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.

EPS Operator 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, EPS Operator requires the IC to provide confirming documentation to EPS Operator that describes the messages and passcode(s). for each DER.

DER Communication Interface

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 EPS Operator specifications.

EPS Operator Protocol

EPS Operator 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.

Monitoring, Control, and Information Exchange

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 EPS Operator.

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 values) and 2-4 seconds (status condition)

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.

EPS Operator reserves the right to require smart inverter interface where needed following the EPS proposed smart inverter setting sheet 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

Machine-connected Generation Requirements

Some Generating Facilities 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.

Generating Facilities that meet the following criteria require implementing Telemetry to the 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 Generating Facility.
- 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 Generating Facility 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 EPS Operator:

- 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 Generating Facilities.

If multiple Generating Facilities over a large area with an aggregate generation greater than 40 MW are being centrally controlled:

- Continuous Telemetry required.
- Aggregate instantaneous MW of all Generating Facilities.

If the generation, for protection, requires transfer trip communication, then generation site transfer trip communication status shall be telemetered.

Generating Facilities 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 38 kV and above

Manufacturer specifications for frequency and voltage protection schemes must be submitted to EPS Operator for review. If this protection is not an integral part of a listed, manufactured power source Interconnection system, EPS Operator shall have the right to require testing of the protection device systems at the IC's expense.

~~11.~~10. 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 EPS Operator.

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 EPS Operator 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.~~11. Commissioning and Verification Requirements

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/ DER Owner /Developer. These requirements will be a subset of the items found in this section.

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.

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)

Evaluation of Documentation

Prior to the performance of commissioning tests by qualified personnel, EPS Operator 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.

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 the 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.

Commissioning Tests

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 EPS Operator, 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 and protection scheme to be implemented
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 EPS Operator and approved by EPS Operator. These settings shall not be altered during commissioning without the authorization of EPS Operator.

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 or DER System and the results of the DER evaluation performed before commissioning.

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 System (PCC).
- Results of DER evaluation by EPS Operator.

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 EPS Operator 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 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:

- Inverter Type
- DER System design Configuration
- DER System Capacity
- Manufacturing Certification of equipment settings
- DER System Field Operating Tests
- Frequency requirements
- Voltage requirements

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 Generating Facilities. EPS Operator 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
Required for systems over 25kW	Trip and Reconnection Test	During testing, open the source 3 times to verify it trips and remains disconnected for at least 5 minutes. The tests shall be as follows: 1. Net export shall be adjusted so that load and generation are reasonably matched, resulting in very small flow. The three-phase interruption device at the interface is opened. 2. Net export shall be adjusted so that load and generation are not matched, resulting in large export. The three- phase interruption device at the interface is opened. 3. Net export shall be adjusted so that load and generation are reasonably matched, resulting in very small flow. One of the phases shall be opened at the interface (open phase condition). In all three cases, the DER shall trip in less than 2 seconds and stay disconnected for at least 5 minutes before automatic reconnection.
Required for systems over 25kW	Load Rejection Overvoltage Test (to be done by operating the PCC interrupter)	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 1.3 p.u. to 1.4 p.u. must not exceed 16 ms o Maximum RMS Voltage Produced by DER at PCC ranging from 1.4 p.u. to 1.7 p.u. must not exceed 3 ms o Maximum RMS Voltage Produced by DER at PCC ranging from 1.7 and 2.0 p.u. must not exceed 1.6 ms
Where system output must be limited to a certain value	Power Limit Function	Set power limit below current Power Export Limit. 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	EPS Operator 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 energy	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) -30% pickup and 5 seconds for testing. The actual reverse power settings pickup can be set as minimum import or actual reverse power, to a very low conservative value, and the time-delay will not be recommended to exceed 2 seconds in line with IEEE-1547 anti-Islanding section, unless load-rejection simulations are provided, justifying the time-delay increase to a higher number that 2 seconds. On PV systems this may be lower. - Verify DER either trips off or isolates to prevent export of power to the Area EPS at the PCC.

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 EPS Operator'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. EPS Operator 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.

Periodic O&M and Testing

Periodic Testing Requirements

The IC must provide EPS Operator 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. EPS Operator 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 manufacturer's recommendations.

Operating and Maintenance Requirements

EPS Operator routinely performs maintenance on its system. While the EPS Operator 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, EPS Operator schedules most routine maintenance during normal daylight working hours. To this end, EPS Operator 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 Generating Facility with the EPS, it may not be possible to do a load transfer with large DERs remaining in service. If the situation is not a System 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 EPS Operator 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 EPS Operator under the provisions of the Standby Service Rate.
- The Customer may request EPS Operator 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 EPS Operator 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 EPS Operator always. At its option, EPS Operator may choose to operate the switching equipment if, in EPS Operator's opinion, continued operation of the Customer's generation in connection with EPS may create or contribute to a System Emergency, and Emergency Condition, 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 EPS Operator's personnel. This equipment must provide a visible break in the circuit.

~~13.~~12. CHP/Cogen

Combined Heat and Power (CHP) and Cogeneration Facilities generally rely on synchronous machines or induction machines for coupling of the Generating Facility to the EPS. Newer CHP technologies utilize microturbine with inverters for generation source. 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 specific to each DER technology, the Customer of a CHP or Cogen facility shall provide EPS Operator with a planned operating schedule for the facility, documenting the anticipated running schedule and power output on at least an hourly resolution. If the Customer 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.

~~14.~~13. Microgrids

A Microgrid is a group of interconnected loads and Distributed Energy Resources (DER) within clearly defined electrical boundaries that acts as a single, controllable entity with respect to the grid. A Microgrid can connect and disconnect from the Grid to operate in both Grid-Connected (Parallel with the Grid) or Islanded Mode (off-the-grid mode). Distributed energy resources DER are essential parts of a Microgrid system. As a result, the regulatory and technical challenges that affect DERs also affect Microgrids in general.

The Microgrid technical requirements outlined in this document cover 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 a Microgrid. For any Microgrid that has to utilize EPS assets - such as utility right of way, wires/conductors, poles, service transformers, or other EPS owned and operated switchgears – special studies, engineering and operation consideration related to the Islanded Mode of Operation (IMO) are required and are addressed in Section 14.10. Islanding studies and verifications are excluded from the scope of Customer Microgrid Interconnection.

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The Microgrid 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 Distribution System.

Technical requirements specific to the DER that are part of the Microgrid are covered in the previous sections of this document. This 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, safely Operate in Parallel with the Distribution System or Network and in Islanded Mode, and to permit sufficient visibility to Distribution System operations to manage operation of the Microgrid together with the Distribution System.

Operating Modes

The Microgrid should be able to operate under the following operating modes:

- **Grid-Connected Mode**: In this mode, the Microgrid is electrically Interconnected with the area EPS. Microgrid may fully or partially supply its internal loads within the boundary, or export power into the EPS up to a pre-specified limit (Power Export Limit). When the Microgrid is Interconnected and Operates in Parallel with the area EPS, the operating requirements for the DER Interconnection described in previous sections of this document and any additional requirements based on the latest edition of IEEE 1547-2018 shall be followed for individual DERs.
- **Islanded Mode**: In case of a disturbance in the EPS or in anticipation of an outage, the Microgrid should disconnect from the EPS and transition to an Islanded Mode, in which the Microgrid will operate in isolation from the EPS while supplying its pre-determined loads as an Island.
    - The Microgrid shall be able to disconnect safely from the EPS in a controlled way and reconnect back to the Grid (either automatically or with operator intervention) when it is safe to do so.
    - Once isolated, the Microgrid shall maintain power quality and reliability criteria defined by the EPS or in accordance with national codes and standards listed in this document for:
        - Power quality
        - Voltage and frequency ranges
        - Grounding and safety
    - The Microgrid shall be able to detect, clear and/or isolate faults in the islanded system.
    - The Microgrid shall include provisions to shed load that exceeds the Microgrid generation capacity when operating in Islanded Mode.
    - Operation of the Islanded Microgrid must not impact the EPS Operator's ability to restore service to its Customer's located outside of the boundary of the Islanded Microgrid.

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The Microgrid shall be able to transition between the Grid-Connected and the Islanded Modes in a controlled manner (connect / disconnect control functions).

- **Operating and Maintenance (O&M) Procedure:** A comprehensive microgrid operation and maintenance specification document shall be prepared for a Microgrid based on the microgrid location, type, configuration, DER technology in use, and control and protection systems to clearly describe the connect/disconnect procedure.
  - The O&M procedure shall provide technical details governing the process of Operating the Microgrid in Parallel with or in isolation from the EPS, including the methods of transitioning from Grid-Connected to the Islanded Mode and vice versa.
  - The O&M procedure shall clearly describe the synchronization scheme, criteria and the process for re-connecting the Microgrid to the Grid. The process shall provide steps involves such as confirmation of the Grid health, measurement, and requirements for coordination with area EPS Operator to obtain permission to re-connect.
  - The O&M procedure shall describe the dispatch scenario(s) for Operating the Microgrid in Parallel with the Grid.

To ensure safety and integrity of the Microgrid operation, EPS Operator shall have the right to establish remote communications to the Microgrid Control System (typically through the MGC) to connect or disconnect the Microgrid from the EPS, or to initiate a planned Islanding.

The Microgrid Owner will be provided prior reasonable notice for any planned (pre-schedule) disconnection that is required by EPS Operator for maintenance purposes or system abnormal operation.

The Microgrid Control System functions are further described in the following section.

~~14.2~~ DERs in the Microgrid

When in the Grid connected Mode, DERs that are part of the Microgrid boundary shall comply with the general technical requirements described in the previous section of this document and any additional requirements from IEEE 1547-2018. The key areas of compliance are:

- Compliance with acceptable voltage, frequency, and power quality
- DER response to Abnormal Conditions
- Utilizing proper configuration and topology for a DER step-up transformer (all DER step-up transformers should have grounded configuration on the EPS side)
- Protection coordination for the DER Interconnection for responding to Grid faults and disturbances such as open-phase detection and loss of the grid
- DER dispatch to maintain any requirement for Power Export Limit/import/ limit
- Revenue Metering and Telemetry
- Safety considerations for protection of public and EPS Operator’s personnel

For inverter-based DER within the Microgrid, EPS Operator may require advanced functionalities for automatic management of Active and Reactive Power for Grid support and reliability enhancement, as described in this document.

Microgrid Controls

Microgrid Controller (MGC) is a set of logic and decision-making algorithms developed in form of software and/or hardware that acts as the supervisory or a master controller. The key MGC role is to coordinate and harmonize operation of various elements in the system including resource dispatch and utilization coordination. The MGC determines Microgrid interactions with the Grid at PCC and the steps involving the decision to switch between the Grid-Connected and Islanded Modes. MGC also coordinates the thresholds (setpoints) for power exchange (Active and Reactive Power) with the Grid such as maximum export limit and demand limit.

In addition, for the Islanded Mode of Operation, the MGC provides frequency and voltage setpoints for DER dispatch and optimization of energy usage or operation cost or any other use case associated with Microgrid. Because of load and generation fluctuations in real-time, additional capacity (either extra spare generation or load control schemes) may be necessary for the proper Microgrid frequency and voltage controls; the provision and control of this additional resources is usually coordinated by MGC.

Basic MGC functions includes (in accordance with IEEE 2030-7):

- Coordinate connection and disconnection of the Microgrids based on pre-defined operating procedures and in coordination with EPS Operator,
- Supporting multiple modes of Microgrid operation, as applicable, such as:
- Conventional generation only, renewable generation only, or a hybrid mode comprising of conventional and renewable generation operating together
- Including an Energy Management System (EMS) to optimally dispatch various generation units based on their special operating characteristics and constraints, as well as Power Export Limit and power import limits.
- Ability to schedule and control Energy Storage System assets to manage and optimize the excess power
- Ability to implement load management schemes to minimize renewable energy curtailment, based on load priority for Customers.
- Implementing and coordinating the black start steps and procedure
- Ability to monitor the state of the system and notify the protection system of a change in state of the Microgrid that may require a change in protection settings

Examples of advanced control and optimization functions that may be include in a MGC are:

- Voltage and frequency restoration through Automatic Generation Control (AGC) in the case of utilizing multiple grid-forming generation units
- Coordinating seamless transition to/from Island, if applicable
- Resource optimization with respect to operating cost and utilization schedule
- Enabling the provision of ancillary services to the Grid in addition to energy market participation for DERs within the Microgrid

To satisfy the Interconnection objectives and to present the Microgrid as a single controllable entity with respect to the grid, the MGC must perform specific functions to fulfil the requirements described in IEEE Std. 2030.7 – Specifications of Microgrid Controllers[4]

Protection System

The Microgrid protection system deliverables must include an AC/DC design drawings package, a short-circuit study, a protection coordination evaluation, and the recommended relay settings to be programmed must be provided in native format.

The design drawing package portion must include the protection Oneline, AC three-line elementary and DC schematics, which shall include Instrument Transformers, circuits breakers, switches, relays devices, relays Inputs/outputs assignments including information of all new and existing electrical physical equipment, as well as protection and controls devices, details of maximum and minimum operating capacity, and any relevant technical detail description, on how the Microgrid can be configured to operate as needed under multiple system configurations scenarios.

[4] IEEE Std 2030.7-2017, Specification of Microgrid Controllers, IEEE Standards Association. IEEE Power and Energy Society

The level of detail that is required to be documented on the drawings are listed below:

- AC elementary three-line diagrams:
  - Each Current Transformers (CT); If multi-ratio (MR) applies must show maximum ratio and set-used ratio by programmed relays, CT class type, accuracy level, thermal factor, unique ID nomenclature, any additional relevant nameplate electrical characteristics and polarity marks orientation based on design.
  - Each Voltage Transformers (VT); must show the voltage class, primary and secondary rated nameplate voltages, available and set ratio used by programmed relays, VT winding connections, unique ID nomenclature, and any additional relevant nameplate electrical characteristics, including secondary fuse size (windings) information.
  - Each bus section must show the ratings information for continuous thermal and short-term withstand rating capability, type, and each bus section must have its unique ID nomenclature.
  - Each circuit breaker must have a unique ID nomenclature and show on the drawings the continuous thermal and short-circuit interrupting withstand capability.
  - Each power transformer, including station service transformers must include primary and secondary rated nameplate voltages, percent impedance information at the measured power base, rated and maximum power capacity, winding connections, type, is applicable and grounded thru an impedance element, the electrical characteristics and ratings information of the grounding element will be required to be shown and documented.
- DC schematics:
  - For each microprocessor relays, the Inputs/outputs (I/O's) used must be labeled and have unique ID nomenclature for each, show relay part numbers, DC sources must show battery details information, DC fuses must show sizes and type information, all terminal blocks must show labels and unique numbers. This applies to the circuit breakers trip and close circuits.

As part of the deliverables, a short-circuit fault study and protection coordination evaluation must be performed. The short-circuit study must provide evidence that no thermal or interrupting withstand rating capability limit of any equipment within the Microgrid or at the Interconnected EPS location due to the addition of the Microgrid is exceeded.

The protection coordination must include technical evidence via the time-current curves (TCC) plots developed as part of the simulations for phase and ground faults for each operating scenario contemplated based on topology changes, proving that under minimum short-circuit fault current contributions the protection coordination will maintain acceptable levels of trip-operating times and coordination margins. The protection coordination evaluation must follow best engineering practices, and Industry available standards.

The considerations for the Microgrid short-circuit and protection impact include, but are not limited to:

- The Microgrid should have a minimal impact on the short-circuit level of the EPS such that the adequacy of the Microgrid protection system is maintained. The impact of the Microgrid on short-circuit level and protection of the EPS should be studied to ensure a protection coordination is maintained under any Microgrid topology change due to the various possible operating scenarios.
- The proposed Microgrid protection must provide a reliable and sensitive fault detection, as well as acceptable trip-operating times, maintaining an acceptable level of protection coordination during external phase and ground faults on the EPS. This evaluation must be provided and shall include all technical basis for the recommended relay settings to be evaluated.
- The fault current contribution of any DER in the Microgrid to the EPS must be evaluated. The short-circuit withstand and interrupting rating of equipment in the EPS shall not be exceeded due to the Microgrid Interconnection. The fault current contribution from DERs in the Microgrid shall not add more than 10% to the maximum short circuit current seen by EPS Operator switchgears (e.g. at feeder head circuit breaker). In addition, the aggregated fault current should be less than

90% of the interruption capacity of any interrupting device or circuit components. Where the fault duty limit has been reached, alternate methods of Interconnection must be explored, and additional fault-current mitigation measures must be taken. These methods and measures may include:

- Reduction of total aggregate synchronous generation at the site to reduce the short-circuit current contribution to an acceptable level.
- Use of alternative generation strategies such as inverter based DERs.
- Use of fast-acting current-limiting protective devices such as G&W CliP, ABB IR limiter, etc.
- Replacing some of the equipment that have reached their interrupting limit because of the Microgrid operation

- The Microgrid, when operating in a Grid-Connected mode, shall be able to trip-operate and isolate from external faults (i.e., faults outside of the Microgrid boundary) as soon as possible such that its impact on the EPS system and equipment thermal exposure are minimized.
- The Microgrid shall be able to clear and/or isolate internal (within the Microgrid boundary) faults in both Grid-Connected and Islanded Modes. As such, the Microgrid internal protective devices must be coordinated with the Microgrid Interconnection Device (MID) Protection.
- The fault clearing times must follow best industry practices and applications to ensure a fast trip-operation and an optimal protection coordination between the existing EPS protection and the Microgrid DER proposed relay protection, this for both Internal and external faults when in Grid Connected Mode.
- The overcurrent protection devices in the Microgrid shall be capable of being adjusted automatically to dynamically adapt to the changes in short-circuit levels as the Microgrid operating condition/configuration changes. Modern microprocessor relays with multiple programmable group settings must be used for this purpose. The protection device within a Microgrid shall have the capability of changing setting groups upon commands by a microgrid Controller.
- When the Microgrid separates from the Grid and is placed in Islanded Mode, it can reduce the overall load of the host feeder (EPS).
- Microgrid DERs should follow EPS Operator's interconnection requirements including proper configuration for their step-up transformer. All DERs within the Microgrid shall be effectively grounded to avoid any Temporary Overvoltage (TOV) condition, upon ground faults (GFOV), or due to load rejection (LROV), which could expose Con the area EPS to extreme voltages.
- All workstations, control, protection, and communications equipment associated with Microgrid operation shall have interruptible/uninterruptible power supply (UPS) through battery backup UPS and DC power supplies. The UPS shall supply power to the control, communications, and protection for a minimum of 8 hours.

Any need for additional protective functions for the proposed Microgrid shall be determined by EPS Operator on a case-by-case basis and EPS Operator shall notify the Microgrid Owner in writing of the requirements. The notice shall include a description of the specific aspects of the EPS Operator's system that necessitate the addition, and an explicit justification for the necessity of the modified or enhanced capability as well as the required settings.

Any protective equipment or settings specified by EPS Operator shall not be changed or modified at any time by the Microgrid Owner or Operator without written consent from the EPS Operator.

Power Exchange at PCC

Control of the Active and Reactive power exchange with the EPS is one of the key technical considerations for a Customer Microgrid operation in the Grid connected Mode, when microgrid generation sources are Operating in Parallel with the Grid. The power import/export limits are normally utilized to avoid extensive facility or system upgrade due to additional DER or a Microgrid.

Based on the Microgrid Interconnection Study, it may be required that a Microgrid shall apply a precise

Active Power control for "*Power Export Limit*" to avoid potential adverse impact of back-feeding at EPS areas that bi-directional power flow is not allowed, such as a feeder head, a substation transformer, or an inline voltage regulator. Similarly, the power import limit may be requested if there is concern with thermal overloading at specific charging rates for an energy storage unit within a Microgrid which would present itself as additional load in the system.

In the Grid Connected Mode, a Microgrid Controller shall be utilized with control capability to precisely regulate the Active and Reactive Power flows at the Microgrid PCC to the setpoints given by either the EPS Operator or pre-specified Power Export Limit/import thresholds.

Upon the request by EPS Operator or based on the outcome and requirements specified in a Microgrid Interconnection Study, the MGC should support scheduling and managing of the following control schemes for DERs within the Microgrid electrical boundary. The MGC shall have the capability to activate/de-activate any of the scheme based on a seasonal schedule or in coordination with EPS Operator dispatch center:

- Energy (defined MWh production setpoint over an interval),
- Capacity (defined MW import/export threshold throughout an interval),
- Setpoints and setting automatic functions, including Constant Power factor control, constant reactive power control, frequency/Watt, Volt/Watt, and Volt/VAR Control schemes.

Constant power factor control scheme

For this scheme, the DERs within the Microgrid shall operate at a Constant Power Factor. The target Power Factor shall be specified by the EPS Operator. The DER should be sized in a way that in maintaining the Power Factor, the Reactive Power requirement shall not exceed the power capability level of the unit. Any other functional requirements for this control scheme should follow the section on DER support of the Grid voltage in this document.

Voltage-reactive power control scheme

For this scheme, the DER within the Microgrid shall actively control its Reactive Power output as a function of voltage following a voltage-Reactive Power piecewise linear characteristic. An example voltage-reactive power characteristic is shown in Figure 14-1. The target characteristic shall be configured in accordance with the default parameter values prescribed by EPS Operator. Any other functional requirements for this control scheme should follow the section on DER support of the Grid voltage in this document.

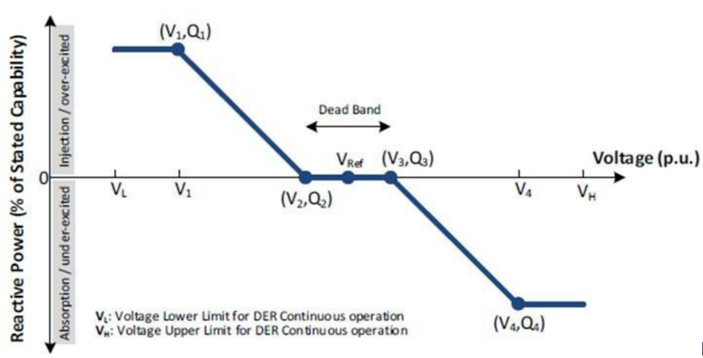

Figure 14-1. Example voltage-reactive power characteristic

Active power-reactive power control scheme

For this scheme, the DER within the Microgrid shall actively control the Reactive Power output as a function of the Active Power output following a target piecewise linear Active Power-Reactive Power characteristic, without intentional time delay. In no case, shall the response time be greater than 10 s. Example Active Power-Reactive Power characteristic is shown in Figure 14-2. The target characteristic shall be configured in accordance with the default parameter values prescribed by EPS Operator. The characteristics shall be allowed to be configured as specified by EPS Operator using the values specified in the optional adjustable range. Any other functional requirements for this control scheme should follow the section on DER support of the Grid voltage in this document.

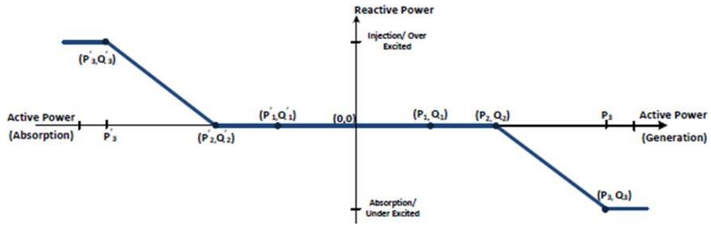

Figure 14-2. Example Active Power-Reactive Power characteristic

Constant Reactive Power control scheme

For this scheme, the DER shall maintain a Constant Reactive Power Mode during the full production range. The target Reactive Power level and Mode (injection or absorption) shall be specified by the EPS Operator during the Interconnection Studies.

It should be noted that the DER advanced control schemes (listed above) are not appliable to a cease to energize state, which may be required for a DER in response to extensive voltage and frequency excursions. In a ceased to energize state, the DER shall not deliver Active Power during steady-state or transient conditions. The requirements for cease to energize shall apply to the Point of Connection (PoC) of the DER.

Voltage Control

The permissible voltage range for Microgrid voltages at PCC during Grid Connected and Islanded Modes shall be from 90% to 110% of nominal voltage magnitude. During the Grid Connected operation, the Microgrid shall not cause the system voltage at the PCC to exceed 95% to 105% of the EPS system voltage (operating voltage range). In addition, the microgrid connection/disconnection or any sudden change in the load and DER within the Microgrid boundary shall not cause more than 3% sudden voltage deviations at PCC.

For voltage excursions outside the operating limits, either steady-state exceedances or fast deviations, the protective device shall automatically initiate a disconnect sequence from the EPS as detailed in the sections on general interconnection requirements and the latest edition of IEEE 1547. Clearing time for under/over voltage is defined as the time the range is initially exceeded until the Microgrid ceases to energize at PCC, and it includes detection and intentional time delay. Other static or dynamic voltage functionalities shall be permitted as agreed upon between EPS Operator and the Microgrid Owner.

Frequency Control

The operating frequency range for a Microgrid during the Grid-Connected Modes shall be from 57.5 Hz to 61.5 Hz (operating range). For frequencies above or below this range, the Microgrid DERs shall follow the Ride Through requirements described in the table below. In addition, the rate of change of frequency caused by DER dispatch within a Microgrid and measured at PCC shall be less than 3 Hz/seconds.

During IMO (when separated from EPS), a Microgrid shall be able to maintain a tight control on Microgrid frequency to stay within 59.5 Hz and 60.5 Hz. If deemed necessary due to Abnormal Conditions, EPS Operator may request that a Microgrid shall operate at frequency ranges below 59.5 Hz in coordination with the load shedding schemes of the EPS

For frequency excursions outside the operating limits the protective device at PCC shall automatically initiate a disconnect sequence from the EPS as detailed in the general interconnection requirement section of this document and the latest edition of IEEE 1547. Clearing time for under/over frequency is defined as the time the range is initially exceeded until the Microgrid's equipment ceases to energize the PCC, and it includes detection and intentional time delay. Other static or dynamic frequency functionalities shall be permitted as agreed upon between EPS Operator and the Microgrid Owner. Table 14-1 shows the operating frequency and tripping requirements for DERs within a Microgrid in the Grid Connected Mode and Islanded Mode of Operation (IMO).

Table 14-1. Operating Frequency Range and Trip Settings for DER in a Grid Connected Microgrid in response to abnormal frequencies and abnormal operation

Freq. Range	Ride Through Req.	Clearing Time (sec)
57.5 - 61.5 Hz	Continuous	No Trip
61.5 – 62.5 Hz	30 sec	30.01 – 90.00 sec (adjustable)
56.5 – 57.5 Hz	10 sec	10.01 – .00 sec (adjustable)
Less than 56.5 Hz or Greater than 62.5 Hz	Instantaneous Trip	0.01 sec

When the system frequency is outside of the ranges given in Table 14-1 and the fundamental-frequency component of voltage on any phase is greater than 30% of nominal, the DER shall cease to energize the Area EPS and trip within a clearing time as indicated.

~~14.8~~ Islanding and Reconnection Requirements

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It is expected that for Customer type Microgrids (non-utility), the Microgrids Microgrid Owner will engage a qualified engineering/consulting firm to design or verify the technical requirements for safe and reliable operation of a Microgrid in an Islanded Mode. This document only covers the technical requirements for disconnection (islanding) and reconnection to the Area EPS.

Islanding Transition (disconnection)

The Microgrid shall have provisions for both intentional (pre-planned) and unintentional (unplanned) Islanding at PCC. The definition and requirements for each transition scheme is described below.

- **Intentional Islanding (planned) condition:** This is a type of islanding transition that the disconnection time and the transition process is pre-planned and fully supervised by the MGC to minimize any impact or extensive voltage and frequency excursion for both the EPS and Customer loads within the Microgrid boundary. This approach may be used for pre- scheduled maintenance or in anticipation of sustained outages. The Microgrid Owner, Operator or the MGC shall coordinate Islanding time with EPS Operator. The power exchange at PCC prior shall be reduced as much as possible. Preference is to maintain a zero-power flow at PCC prior to disconnection.
- **Unintentional Islanding (unplanned) condition:** This is a type of Islanding transition for which the disconnection time is unpredictable (un-planned), which could happen in response to a fault on the Area EPS outside of the Microgrid boundary or due to voltage and frequency excursions beyond the acceptable power quality ranges tolerable by Microgrid loads.
- **Break-before-make Islanding transition method:** The Microgrid Owner/Operator may choose to perform a break-before-make approach for transition from the grid connected to the islanded Mode. In this approach, the DER in the Microgrid are disconnected prior to opening of the MID, which will result in a load interruption once the MID is open. Once the microgrid is fully separated from the EPS, black starting approach for DER will be used to re-energize the Microgrid and restore the Grid. Apart from the fact that microgrid loads will experience a period of power outage, this is the safest and most utilized approach for Island formation which prevents any major transients and stability issues.
- **Seamless Islanding transition method:** In this method, the DER in the Microgrid in coordination with MGC will attempt to Ride Through the Islanding transients and continue supply the microgrid load when MID is opened. To seamless transition requires minimizing the power export prior to the MID disconnection or utilize DER with proper voltage and frequency control functions that can rapidly regain the balance of power after loss of the Grid. Maintaining Microgrid stability is a key aspect of such transient method. As such the method is most effective for planned Islanding condition that provides provision for minimizing power exchange at PCC.

Technical requirements specific to disconnection:

- Microgrid Interconnection Studies shall analyze both intentional and unintentional Islanding scenarios to ensure the sudden voltage deviation at PCC after M Microgrid disconnection is less than 3%.
- The Rate of Change of Frequency at PCC due to Microgrid disconnection shall be less than 3 Hz/seconds. Otherwise, additional import/export limits may be imposed on the Microgrid at PCC.
- Microgrid disconnection shall not cause thermal issues or reverse power flow at any part of the Area EPS.
- Microgrid Owner, Operator or MGC shall notify EPS Operator once the transition is completed to determine any change of protection settings or schemes for the Area EPS.

Synchronization (reconnection)

The Microgrid shall have provisions for synchronizing in one or more of the following methods at the Microgrid PCC:

- **Active synchronization method**: In this method, the voltage and frequency of the isolated Microgrid should be actively adjusted to properly align with the EPC voltage and frequency before closing the PCC switch. This method is very effective when there is multiple Grid Forming DER in a Microgrid. The auto-synchronizer function in the MGC shall measure the Grid side values at

PCC and provide voltage and frequency setpoints for the Grid Forming DER in the Microgrid to meet the synchronization criteria according to the latest edition of IEEE 1547 and listed below. MGC sends a closing command to MID, once the condition is met. A sync-check relay shall be utilized at PCC to block closing of MID if there is difference in the expected criteria and independently measured value by the sync-check function.

Table 14-2. Synchronization criteria for Microgrid

Parameter	Aggregate generator Size (kW)		
	0-500	500-1,500	1,500 +
Voltage Difference (ΔV) in %	10	5	3
Frequency Difference (Δf) in Hz	0.3	0.2	0.1
Phase Angle Difference (Δϴ) in degrees	20	15	10

- **Passive synchronization method:** This method is normally used when there is only one Grid Forming DER in a Microgrid. In this case, the voltage measurement waveform from the Grid side of the MID through a PT or a voltage sensor is sent directly to the DER. Using the measurement, the DER would match the voltage magnitude and set the frequency slightly below the Grid frequency to create a very small slip frequency difference. A sync-check relay will verify the synchronization condition and will close the MID.
- **Use of a Sync-Check relay**: In either active or passive synchronization scheme for the Microgrid, a sync-check relay shall be utilized for MID to block out of sync reconnection at PCC if the voltage and frequency of the isolated Microgrid and the area EPC are not within the synchronizing tolerances. The Microgrid Controller should re-initiate reconnection of MID, if the sync-check function report “time out”.
- **Open Transition (break-before-make)**: This method involves de-energizing all DER units in the Islanded Microgrid, and then closing the MID at PCC for reconnection to the EPS. Once reconnected, the DER will require to verify presence of a healthy voltage and restart as desired. This is the simplest option for reconnecting the Microgrid back to the EPC, but the impact of interrupting the loads should be considered.
- **Technical requirements specific to reconnection:**
    - Reconnecting Microgrid back to EPS should not create sudden change in the Grid voltage at PCC more than 3% or violate the EPS steady-state operating voltage ranges
    - The load transfer after reconnection should be performed gradually to prevent any excessive Rate of Change of Frequency (more than 3 Hz/seconds) or Reactive Power inrush.
    - Within 30 seconds (adjustable delay) from completion of a Microgrid reconnection transition, MGC shall activate Power Export Limit, according to the requirements and thresholds agreed in the Interconnection Study.
    - Microgrid Owner, Operator or MGC shall notify EPS Operator once the transition is completed to determine any change of protection settings or schemes for the area EPS.
    - Because EPS Operator does not allow using grid-forming operation in the Grid Connected Mode, the Microgrid owner, Operator or MGC shall arrange for DER control model change and provide confirmation of the grid-following control mode to EPS Operator within 2 seconds (adjustable delay) from completion of transition method. The Grid Following Mode normally requires enabling active anti-Islanding scheme for inverter-based DER, especially if seamless transition for Islanding Mode is not expected.

IMO Requirements for Mixed-Ownership Microgrids

For Microgrid that utilizes any EPS assets, additional studies and engineering will be required to ensure that Microgrid DERs can provide a reliable and safe power delivery to Customers without any safety or harm to the EPS assets. The Microgrid shall be able to maintain the power quality requirements specified in this document throughout the entire duration of operating in IMO separately from the Grid.

Comprehensive Islanding studies (electromagnetic transient analysis with use of PSCAD/EMTDC software tool) shall be performed to ensure Microgrid can operate safely and reliably by regulating voltage and maintaining frequency of the Islanded area. The studies shall consider the following studies scenarios:

- Assessing voltage and frequency controls across the Microgrid, during a black-start scenario, when Islanding transition has been break-before-make.
- Assessing voltage, frequency and power quality across the Microgrid boundary, during load restoration process
- Assessing voltage, frequency and power quality across the Microgrid boundary, during load fluctuations, energization, motor start or any sudden load switching that requires fast load following capability.
- Assessing voltage, frequency and power quality across the Microgrid boundary, during any capacitor switching or sudden drop in solar PV production (e.g. 80% reduction), if any PV systems are included in the Microgrid boundary.

Additional protection and effective grounding studies shall be performed to verify that DERs within a Microgrid that is separated from the EPS can detect and clear internal faults, as well as there would not be any concern with GFOV or LROV in the IMO.

All the study approaches and detail study scenarios (such as peak load and daytime load or minimum load) shall be coordinated with EPS Operator distribution planning.

Additional testing and verification of the Microgrid performance for the IMO is required, such as black start testing (with use of a load bank), load restoration and load following tests to verify voltage and frequency regulation in Islanded Mode.

EPS Operator reserves the right to require remote control access and monitoring of the Microgrid operation and DER control through a dedicated Microgrid Controller or existing monitoring/control schemes, as long as the controls meet the cybersecurity considerations.

Power Quality Requirements

For the power quality requirements of Microgrids, refer to section 9 of this document. The requirements apply to both the GCM or IMO (Grid Connected or separated from the Grid).

EPS Operator Limitation of Dc Injection: the DER shall not inject dc current greater than 0.5% of the full rated output current at the Reference Point of Applicability (RPA).

Metering Requirements

The Microgrid shall have appropriate and adequate revenue-grade Metering equipment where needed for measurement of Active and Reactive Power exchange with the EPS, energy (interval data), voltage and frequency at PCC, connection/disconnection time, DER production data, and other Metering data as required for compensation or remuneration of services provided by the Microgrid.

Metering equipment is required at the following points within the Microgrid:

- At the Microgrid PCC to account for power exchange and cumulative energy (bidirectional) between EPS and Microgrid. EPS Operator may require power quality measurement and reporting at PCC for certain Microgrid (based on Interconnection Study)
- At each DER Point of Interconnection point for individual Metering of power and cumulative energy
- At load service points for individual Metering of the entities participating in the Microgrid when in Grid-Connected or Islanded Mode.

If the Customer's existing metering equipment is not capable of measuring both the amount of electricity delivered by EPS Operator to the Microgrid and the amount of electricity delivered by the Microgrid to the EPS, then the Customer shall pay for the cost of new Metering equipment that meets these requirements.

~~14.12~~ Communications, monitoring, and cybersecurity requirements

Communications and Monitoring Requirements

For all Microgrids connected to the primary feeders and certain Microgrids on secondary systems, there shall be a communication line established between the Microgrid Controller (MGC) and the Area EPS Operator for coordinating power exchange with the grid, providing updated status of DERs within the Microgrid, and obtaining permission for connection/disconnection.

Within the Microgrid, the DER shall have provisions for a local DER communication interface capable of communicating with MGC to support the information exchange requirements for all applicable functions that are supported in the Microgrid. The information to be exchanged falls into the following four categories:

- Nameplate information: This information is indicative of the as-built characteristics of the DER. This information may be read.
- Configuration information: This information is indicative of the present capacity and ability of the DER to perform functions. This information may be read or written.
- Monitoring information: This information is indicative of the present operating conditions of the DER. This information may be read.
- Management information: This information is used to update functional and mode settings, or send setpoints to the DER. This information may be read or written.

The communications between EPS Operator and MGC should meet EPS Operator’s telecommunication requirements. The preferred communication protocol is DNP3 over Ethernet (TCP/IP)

As a minimum, Table 14-4 provides a list of key data points (monitoring and control parameters) that should be supported by MGC for communications between EPS Operator’s SCADA/DMS and any Microgrid connected to the primary feeders.

Table 14-4. Key Microgrid data points for information exchange with EPS

Monitoring Parameters	Control Parameters
Communication health status	Voltage setpoint for PCC
Voltage measurement at PCC	Power Export Limit
Current measurement at PCC	Power Import Limit
Voltage phasor measurement	Power Factor setpoint at PCC

Current phasor measurement	Permission to reconnect
Active power at PCC	Planned Island request command (intentional Island)
Reactive power at PCC	Active Power dispatch setpoint
Energy measurement	Reactive Power dispatch setpoint
Power Factor measurement	Sync-check initiate command
Reserve capacity (e.g., State of Charge for ESS)	Emergency disconnect command (shutdown)
Rate of charge measurement	Volt-VAR setpoints
Rate of discharge measurement	Frequency-Watt setpoints
Status of MID	
Grid connection mode	
Frequency	
Control mode	

Cybersecurity Requirements

The Interoperability and communications cyber requirements of specific Microgrid deployments should be based on mutual agreement and shall follow industry best practices and regulatory requirements. The key guidelines for cybersecurity design of the Microgrid are adapted from requirements of NERC critical infrastructure protection (CIP) parts 001-0145 that covers physical security, personnel security, training and awareness, configuration management and vulnerability assessments – irrespective of voltage applicability. Figure 14-3 provides a high-level overview of the basic and advanced security controls that can be used to effectively secure the DER infrastructure. Similar approaches can be used for the Microgrid Control System (MCS).

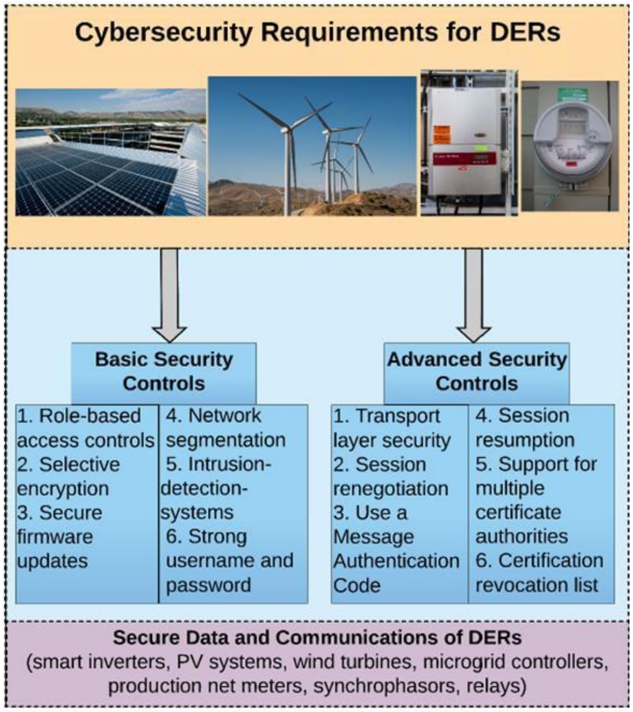

Figure 14-3. High-level overview of cybersecurity requirements for DERs and Microgrid[5]

Basic security controls are best practices for communication networks and control devices within a Microgrid boundary that may have point of communication interface with EPS network. These should be considered necessary but not sufficient for DER and Microgrid cybersecurity.

Some basic security controls recommended for MGC are:

- Using role-based access controls on network equipment, firewalls, and controller (MGC and DER site controller),
- Using network segmentation with different virtual local area networks to create logical segmentation between operational technology, information technology, and management networks
- Periodically updating software security patches and firmware
- Creating strong passwords and not using default factory passwords

[5] A Survey of Protocol-Level Challenges and Solutions for Distributed Energy Resource Cyber-Physical Security by Aditya Sundararajan (1), Aniket Chavan (2), Danish Saleem (3) and Arif I. Sarwat (1).

(1) Department of Electrical and Computer Engineering, Florida International University, Miami, FL 33174, USA

(2) Electrical Engineering Department, Southern Methodist University, Dallas, TX 75275-0340, USA

(3) Energy, Security & Resiliency Center, Energy Systems Integration Facility, National Renewable Energy Laboratory, Golden, CO 80401, USA

- Selectively encrypting to minimize processing overhead and communications latency
- Systemically securing the network using context-based and signature-based intrusion-detection systems and by using in-line blocking tools
- Disabling all unused ports and processes to eliminate unauthorized access

Stringent security controls are also required by a given communications or Interconnection standard for DER controls and automation technologies within a Microgrid. Recommended stringent security controls include:

- Support the use of the National Institute of Standards and Technology (NIST) Guidelines for the Selection, Configuration, and Use of Transport Layer Security (TLS) Implementations (SP 800-52)[6].
- Support the use of the following TLS implementations.
    - Session resumption should occur if the session is severed for the time shorter than the TLS session resumption time using the secret session key.
    - Session negotiation should occur if the session is severed for the time longer than the TLS session renegotiation time.
- Support the use of a message authentication code (MAC).
- Support the use of authorized multiple certificate authorities for the device under test and server.
- Determine a capability for terminating a session if a revoked certificate is used to establish the connection.
- Determine a capability for identifying and terminating a session if an expired certificate is used to establish the connection.
- Disable all unused physical ports, e.g., Universal Serial Bus ports, ethernet ports.

Safety Requirements

The safety of the general public and EPS personnel shall not be reduced or impaired as a result of the Interconnection and operation of the Microgrid system. Any safety risks of the Microgrid shall be analyzed with these considerations is mind. As risks are identified, mitigations should be put in place to manage these risks. These mitigations can come in the form of applying proper signage, updates to safe workplace practices for line personnel, additional lock-out-tag-out procedures, or conducting additional studies. Customer shall apply safety labels with a warning on “Bidirectional Power Sources” and “Electric Shock” should be positioned on the corresponding switches.

The Microgrid shall be designed to incorporate proper grounding system compatible with EPS grounding practices and the requirements of the National Electric Codes. All DERs within the Microgrid shall be effectively grounded to avoid any Temporary Overvoltage (TOV) condition, upon loss of the Grid condition, which could expose Customers on the area EPS to extreme voltages. If requested, Customer shall perform grounding analysis and provide evidence of effective grounding.

The EPS Operator shall be provided with the capability to remotely view the status of the Microgrid, even the ability to shut down the Microgrid and its DER, if necessary, when an Abnormal Condition occurs, such as formation of an Island extending beyond the boundary of the Microgrid, loss of synchronism, or Abnormal Conditions of voltage, power flow, or frequency at the PCC or in any section of the Microgrid.

Verification Test

Microgrid Interconnection verification testing is required to confirm that a Microgrid Interconnection has properly implemented the requirements and the Microgrid is capable of safely disconnecting from and reconnecting to the Area EPS. The three steps of verification testing described in further detail include:

[6] https://csrc.nist.gov/News/2019/nist-publishes-sp-800-52-revision-2

- Pre-energization verifications and tests
- Commissioning tests
- Periodical tests and reporting

It should be noted that the testing requirements for DERs within the Microgrid shall be evaluated separately based on the EPS Operator's DER Interconnection requirements and have not been addressed in this section. The verification tests cover the specific Microgrid Interconnection requirements and control functions to evaluate ability for connecting / disconnecting properly to/from the EPS and dispatching the aggregated DER and loads within the Microgrid boundary as one aggregated entity during the Grid Connected Mode.

EPS Operator reserves the right to conduct Witness Testing with respect to one or all the tests associated with Micrograms as deem necessary. The Microgrid applicant shall provide a final copy of the test procedures (or test plan) in a format prescribed by EPS Operator at least 3 weeks in advance of the testing to give ample time for test procedure review and approval prior to the test and verification date.

EPS Operator reserves the right to witness one or all the tests associated with Microgrids as deem necessary. The Microgrid applicant shall provide a final copy of the test procedures (or test plan) in a format prescribed by EPS Operator at least 3 weeks in advance of the testing to give ample time for test procedure review and approval prior to the test and verification date.

Pre-energization Verifications and Tests

Before performing any test, it shall be confirmed that the Microgrid documentation (as-built package) is consistent with the submitted application and other required project documentation. This evaluation will determine whether commissioning can proceed and the level of commissioning tests that are required. After the completion of the installation, the Microgrid Owner must perform all acceptance testing on the installed interconnection electrical equipment as well as the operational tests and calibrations on the Protective Relays.

It should be noted that, until pre-energization validation is completed, the new DER that is part of the Microgrid application and operation should not be connected to the area EPS. The Microgrid Owner can keep the PCC switch closed to feed internal loads and provide station service power supply to the Microgrid assets (such as control and monitoring equipment, or communication systems).

As-Built Package Verification Requirements

The following steps are required for as-built verifications:

- Review Customer's/DER Owner's/ Developer's project requirements, project specifications, and area EPS requirements for information specifically related to the DER certifications and type test requirements, production test requirements, and project-specific settings and configurations.
- Verify safety manual, electric safety inspection confirmation documentation by the electric safety authority, and Microgrid operating procedure and maintenance manual updated based on final installation and implementation of Microgrid assets.
- Verify that the Interconnection Agreement between the Microgrid Operator and EPS Operator, if required, has been agreed upon (note that a Microgrid Interconnection Agreement is not considered fully executed until the test and verifications are complete).
- Verify that Microgrid interconnection settings (for Protective Relays or controllers, as applicable) meet requirements set by the Area EPS Operator.
- Verify the operating modes that will be implemented at the time of commissioning.
- Verify means of maintaining "power export level" as agreed in the Interconnection Application.
- If the Microgrid is required to provide Grid supporting functions, such as Voltage Control or Ride Through capability at Microgrid PCC,
- Verify the Microgrid can meet the applicable categories for voltage and frequency Ride Through

according to the section on DER response to Abnormal Conditions in this document. Document required settings for the operation.
  - Verify the Microgrid can meet the applicable categories for the Grid voltage support specified in this document. Document required settings for the operation.
  - Record all settings for response to abnormal voltage and frequency conditions or other Abnormal Conditions and verify compliance with Interconnection requirements.
  - Record all enabled voltage/power control functions and settings.
  - Confirm operational coordination with EPS assets (e.g. voltage coordination with tap changers or in-line voltage regulator settings, or protection coordination).
  - Verify unplanned Islanding detection operation and state interval time from initiation of the Island to cease-to-energize.
- If available, review power systems simulation and models to verify DER characteristics were properly characterized. Include summary and source data for any engineering verification of the chosen components or modeling and simulation of the DERs forming a system.
- For requirements that should be supported based on a protection study, confirm protection settings for DERs and Protective Relays within a microgrid.
- If applicable, describe Interoperable functions and requirements for information exchange between EPS Operator (and their DMS/SCADA system) and Microgrid Owner/Operator (and the local controllers). Each description should include all particulars to confirm compliance with the Interconnection Application and Interconnection Agreement.
- Based on the above requirements, provide a list of Microgrid functions and Interconnection features that must be verified during the commissioning stage.

Installation Inspections

Microgrid Owner to schedule a pre-energization inspection of the Microgrid Interconnection Equipment. Microgrid Owner should arrange for any type test or conformance testing that are required by the EPS Operator (e.g. injection testing of relay settings) to be performed at the time of inspection.

The applicant shall inform EPS Operator well in-advance of the inspection to coordinate any Witnessing Testing requirement.

Corrective Actions and Exceptions

Once the pre-energizing verification and tests are complete, any non-compliance, and/or recommendations for further verification should be documented and used in the remaining steps of the verification process:

- Identify technical requirements that should be verified during the commissioning test. This information should be communicated to all stakeholders after the evaluation.
- Identify any system modifications or corrective actions that should be completed prior to commissioning

Commissioning Tests

Commissioning tests shall be applied to a Microgrid after construction is completed, pre-energization inspection is performed and the Microgrid is permitted to be connected to the Grid. The commissioning tests shall evaluate the impact of the Interconnection of the Microgrid to the EPS. The commissioning tests to be performed depend on the pre-energization verifications and test results before commissioning, the type of Microgrid, and the Point of Common Coupling between the EPS and the Microgrid owner and will be evaluated in case-by-case basis by EPS Operator.

The Microgrid Owner shall prepare a test plan that includes at a minimum (but not limited to) the operation of the protection and control system, Microgrid Controller, PCC switch, electrical interlocks, Telemetry, Metering, switchgear, and grounding devices. A complete acceptance test plan (or test procedures) as well as the Protective Relay certification test report must be submitted to the EPS Operator for approval a minimum of two weeks before executing commissioning tests.

All commissioning tests shall be performed based on written test procedures submitted for approval a minimum of two weeks in advance of any scheduled test. EPS Operator representatives may be present for the mutually agreed tests. Table 6-1 provides examples of commissioning tests that may be requested to be performed. Additional tests may be requested after review of a submitted test procedure by the Microgrid Owner or Operator and as the result of pre-energization verifications.

For Microgrid connecting to primary feeders, when PCC is on medium voltage (based on the location of MID), EPS Operator may arrange for a Hot Stick Test for further verification of proper synchronization with the Grid for evaluating the Microgrid synchronization and reconnection capability.

Table 14-5. Microgrid test categories based on the application

#	Commissioning Test	Commissioning Tests	Performance Acceptance Tests	Periodical Tests
1	Protection Schemes Associated with MID or PCC switch	X	X	X
2	Individual DER tripping and check	X	X	
3	Microgrid synchronization and re- connection	X	X	X
4	Power Export Limiting Test (MGC function)	X	X	X
5	Unplanned and Planned Islanding tests	X	X	
6	Grid support functions, for Microgrid using EPS assets (voltage/frequency controls, voltage/frequency Ride Through)	X	X	
7	Demand management (import control), if required	X	X	
8	Communications / Telemetry	X	X	X
9	Black start – for IMO	X	X	X

Periodical Tests and Reporting

The purpose of periodic tests is to verify that the Microgrid continues to meet the requirements as established at the time of commissioning and energization.

Periodic maintenance and inspection of the Microgrid and the associated equipment can improve the Microgrid's security and reliability. Periodic maintenance depends on the Microgrid assets and is site-specific and should be covered in the Interconnection Agreement between EPS Operator and the

Microgrid Owner or Operator. The Microgrid Owner or Operator shall follow EPS Operator's procedures and provide EPS Operator with calibration and functional test data for the associated equipment upon request. Minimum intervals are indicated in Table 14-6.

Table 14-6. Minimum intervals for calibration and functional test data

PCC switch	Microgrid Controller	Communication /Telemetry	Relays
Every 5 years	Every 2 years	Every 2 years	Every 5 years

Periodic test reports or a log for inspection shall be maintained, and the Microgrid owner must include the identities and qualifications of the people who performed the tests. EPS Operator personnel may need to Witness the Testing periodically. The EPS Operator may also request special relay tests to investigate possible missed operations.

Additional Tests

In addition to the periodical tests, a re-verification test may be required when any of the following occurs:

- Functional software or firmware changes have been made on the Microgrid assets (DERs, MGC, or Protection Relays). The changes to the software or firmware should be first type-tested and results to be submitted to the EPS Operator for review, in advance of any re-verification testing.
- Any hardware component of the Microgrid has been modified in the field or has been replaced or repaired with parts that are not complying with Microgrid certifications and compliance documents.
- Protection functions have been adjusted after the initial commissioning tests.
- Operating modes or settings have been changed after the initial commissioning tests.

In addition, if EPS Operator identifies any field operational and performance issues due to power quality, power quality tests per the appropriate power quality standards shall be required and scheduled by the Area EPS Operator.

~~15.~~14. Transmission and Sub-Transmission Interconnections

Scope

This section outlines the technical requirements for Interconnections of DER and generation sources, seeking to connect to the Transmission System or sub-transmission system.

The minimum Interconnection requirements for DER or a generation source with a size less than 5MW AC, Interconnecting to the Transmission System or sub-transmission System, are summarized in section 15.2. The DER size is defined as the addition of all connected generator(s) AC ratings combined, even if the Customer plans on not running them all simultaneously. This calculation excludes generators that are used only during Grid disconnection (backup only units).

Technical Requirements less than 5MW AC capacity

The purpose of this section is to outline the minimum technical requirements for Interconnecting DER with a rated capacity less than 5MW AC to the Transmission System and sub-transmission system grid.

Applicable Standards

All equipment shall comply with applicable standards and local regulations including IEEE 1547-2018, UL 1741 (including SA and SB), IEEE 519, IEEE 1453, and IEEE/ANSI C37.90. A more thorough list of applicable standards is included in Appendix A of this document.

Protection and Control

For DERs<500 kW, EPS Operator will accept the protection functions integrated into the inverters, provided that the proposed functions and settings are formally submitted to EPS Operator for a formal technical evaluation and discussions before approval for final implementation. EPS Operator will provide feedback as necessary to ensure that the selected functions provide the minimum acceptable functions required to protect the DERs. Some typical functions for DERs<500 kW that may be required are overvoltage, undervoltage, over frequency, under frequency, unbalance detection (open phase), phase and ground overcurrent detection, etc. These applications will be discussed on a case-by-case basis.

The physical design specifications and requirements at the Point of Interconnection (POI) for DERs=>500 kW is that the substation of the Customer to which the DER is to be Interconnected must be protected by circuit breakers. Other requirements such as when issuing the electrical drawings, these must follow industry standards and best engineering practices with all the level of details required for EPS Operator to perform a detail review of the proposed addition. EPS Operator will provide the level of details needed to be able to complete the technical review and approval of the proposed protection design, short-circuit study, protection coordination and relay settings recommended set values before they are issued for implementation.
For DERs 500kW or greater, the minimum functions required for the protection of the DER Interconnection with a capacity of 500 kW or more, which can be synchronous, inductive, wind turbine generators, combine heat-power (CHP) technology, that are proposing to be connected to EPS Transmission System or Sub-transmission system; these must have as part of their design a microprocessor relay capable to be programmed to provide the minimum acceptable functions required to protect the DERs.

Some typical functions for DERs 500 kW or greater that may be required are phase overvoltage, phase undervoltage, residual overvoltage, over frequency, under frequency, reverse power for KW and KVars, phase and ground overcurrent detection, etc. These applications will be discussed on a case-by-case basis. These protective functions are listed below in the same order:

a. 59 - Overvoltage *(overvoltage)*
b. 27 - Undervoltage *(undervoltage)*
c. For ground failure detection in delta systems, the relay may have one of the following functions:
   - *59N or 59G — Overvoltage in neutral or ground connection *(ground or neutral overvoltage)*
   - 27/59 — Undervoltage and overvoltage in one phase of the *system.*
d. 810 - *Over frequency*
e. 81U - Low Frequency *(underfrequency)*
f. 32 - Real and reactive directional power (Watts and VARs directional power) To limit the flow of energy to the Authority system when required.
g. 50 - Instant *overcurrent*
h. 51 - Time-delay overcurrent

The voltage and frequency compliance requirements, and that EPS Operator will be required to be programmed on the Inverters or the Protective Relay used for the Interconnection of the DER in the EPS Operator 's electrical system, will be shared with the Customer/DER Owner/Developer as part of the process.

The physical design specifications at the Point of Interconnection (POI) for DERs =>500 kW require that the substation of the Customer client to which the DER is to be Interconnected must be protected by circuit breakers. Other requirements, such as when issuing the electrical drawings, must follow industry standards and best engineering practices with all the level of details required for EPS Operator to perform a detail review of the proposed addition. EPS Operator will provide the level of details needed to be able to complete the technical review and approval of the proposed protection design, short-circuit study, protection coordination and relay settings recommended set values before they are issued for implementation.

The Customer with a DER with a capacity of 500 kW or greater must deliver a short-circuit study and a coordination study with all programmed protection settings, including logical control equations, inputs, and relay outputs. These studies must include, at least, the following information:

a. Short Circuit Study:

The short circuit study consists mainly of performing simulations of three-phase and phase-to-ground failure at different points of the Customer facilities, starting at the point of delivery of the electricity service and ending at the location of the inverters. This information is necessary to verify the coordination between the different protection devices connected in series between this point of delivery and the inverters. The study must include the simulations mentioned for two cases: one where the Customer facility is Interconnected to the EPS and the DER is disconnected, and the other where the DER is Interconnected to the EPS. For the Customer to carry out this study, EPS Operator must provide Customer with information on the Thevenin equivalent impedance of the electrical system at the point of delivery of the service.

The short-circuit study report should include at least the following:

1. Short circuit current input for each inverter.
2. The sum of the short circuit current input of all inverters.
3. Duration of the short circuit current supply of the inverters.
4. Simulated three-phase and phase-to-ground short-circuit current values for both the disconnected DER from and for the case of the DER Interconnected with the EPS in at least the following locations:

- Service delivery point.
- Secondary side of the Customer substation transformer.
- Secondary side of the Interconnection transformer.
- Interconnexion tip of the DER and its inverters.
- Where there is a change in the voltage level within the Customer premises.

b. Coordination Study:

The coordination study uses the results of the short-circuit study described above as a base to determine the necessary settings on the different existing protection devices, and to be installed as part of the DER project.

The selected settings must provide effective and adequate protection of both the EPS electrical system, in compliance with the requirements of this document and the present applicable industry standard codes and best engineering practices. The coordination study is carried out for two main cases: protection of installations during three-phase and phase-by-phase failures, known as phase protection, and during phase-to-ground failures, known as ground protection. The report of the protection coordination study should include at least the following:

1. Adjustments and features of all protection devices installed between the service delivery point and the DER inverters. These devices include, but are not limited to, switches with built-in overcurrent (i.e. *molded-case breakers),* Protection Relays, and fuses. In the case of fuses, information on the manufacturer, capacity and speed of the fuses should be included.
2. *Time-current curves* (TCCs) of all relays and fuses evaluated in the study.
3. Operation time of each device or protection function, both for phase and ground protection.

The Customer with a DER with a capacity of 500 kW or greater is responsible for testing the relay with the approved adjustments in the evaluation of short circuit and coordination studies, and for delivering there port thereof, digitally signed by a certified and collegiate electrical engineer. The report must include the notes that are necessary to explain the results of the relay testing and show that they are satisfactory. The report also must present the adjustments of the relay as left, that is, as previously approved by the EPS Operator's protection, automation, and controls (PAC) and as programmed and tested in the field.

Facilities containing DERs greater than 500kW require a three-phase fault interrupter installed at the PCC to allow three-pole disconnection of the facility by the EPS Operator in case of a Customer-side fault or mis operation.

Reactive Power Requirements

Unless EPS Operator requires otherwise, the default setting is unity Power Factor. The DERs should have the full capabilities mentioned in Section 6. EPS Operator reserves the right to ask the DER Owner to change the settings in the future as necessary.

Response to frequency variation at the Point of Interconnection

This requirement is applicable to DERs >1MW. The DER must provide a primary response to variations in frequency. This must be proportional to the deviation of the nominal frequency, similar to the governing response of a conventional generator. The response to frequency variation has to be 5% or lower, which is the slope (droop) used in conventional generators. This response has to be determined with the nominal AC capacity of the DER. The DER has to provide, as a minimum, response for positive and negative variations in frequency up to 0.3 Hz plus ally of a dead band of 0.02% 0.012 Hz.

In cases where Energy Storage Systems are used to comply with this requirement, the design must include, as a minimum useful energy for situations where the frequency decreases equivalent to a response of 10% of the nominal AC capacity by nine minutes and take one minute to reduce this participation at a rate of 10% of the AC capacity per minute. The design has to contemplate this same energy storage capacity by the time the frequency increases. The operational range of the DER for-frequency response has to be 10% to 100% of the AC capacity of the DER.

Power Quality

DERs connected to the Transmission System or Sub-transmission shall meet the requirements contained in Section 9.

Transient Mathematical Model

DERs larger than 1 MW shall provide a detailed dynamic PSS/e model of the facility.

Dynamic System Monitoring Equipment

DERs larger than 1 MW shall provide and install and commission a dynamic system monitoring equipment that conforms to EPS Operator specifications.

Technical Requirements (MTR) for more than 5MW AC capacity

Generation sources above 5 MW shall comply with Section 15.2 of this document unless the generator intends to export energy into the system. In such case, generator must comply with the Minimum Technical Requirements for utility scale projects, as required in PREB Renewable Integration Process Case No. NEPR-MI-2020-0012.

15. Forms and Agreements

Interconnection Forms and Agreements are added in the following Appendices of this TIR document:

Appendix I: Generator Interconnection Application

Appendix J: Simplified Interconnection Application and Agreement

Appendix K: Certification of Generator Equipment Packages

Appendix L: Feasibility Study Agreement

Appendix M: System Impact Study Agreement (to be used for both Transmission and Distribution System impacts)

Appendix N: Facilities Study Agreement (to be used for both Transmission and Distribution System impacts)

Appendix O: Interconnection Agreement

Appendix P: Agreement for Participation in the Shared Net Metering Program

Appendix A: Reference Standards, Certifications and Guidelines

Industry Standards:

- ANSI C84.1-1995 Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)
- ANSI Std C62.92 APPLICATION OF NEUTRAL GROUNDING IN ELECTRICAL UTILITY SYSTEMS
- CBEMA and ITIC Requirements
- EPS Operator System Planning and Design Criteria for EPS Operator
- IEEE Std 100-2000, IEEE Standard Dictionary of Electrical and Electronic Terms
- IEEE Std 1453 Recommended Practice for the Analysis of Fluctuating Installations on Power Systems
- IEEE Std 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems (including use of IEEE 1547.1 testing protocols to establish conformity)
- IEEE Std 519-1992, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems; and
- IEEE Std 929-2000 IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems
- IEEE Std C37.108-1989 (R2002), IEEE Guide for the Protection of Network Transformers
- IEEE Std C37.90.1-1989 (R1994), IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems
- IEEE Std C37.90.2 (1995), IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers
- IEEE Std C57.12.44-2000, IEEE Standard Requirements for Secondary Network Protectors
- IEEE Std C62.41.2-2002, IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000V and Less) AC Power Circuits
- IEEE Std C62.45-1992 (R2002), IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000V and Less) AC Power Circuits
- IREC Guidelines, Solar ABCs
- NEMA MG 1-1998, Motors and Small Resources, Revision 3
- NEMA MG 1-2003 (Rev 2004), Motors and Generators, Revision 1
- NFPA 70 (2002), National Electrical Code
- PREB Regulations
- UL 1741 (Including SA &SB) Inverters, Converters, and Controllers for Use in Independent Power Systems

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

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Appendix C: Typical Relay Requirements per Plant Configuration (Radial Circuits)

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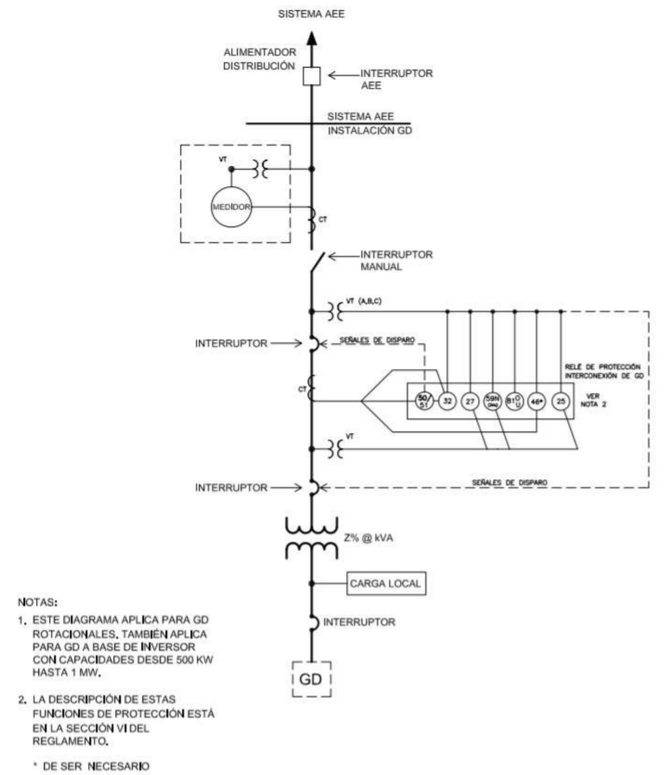
Common DER Configurations			*These are general guidelines for protection requirements and may vary based on IC's total system configuration. Individual protective device functions may be implemented using multifunction relay.+*					
Config 1a	**Config 2a, 2b, 3a, 3b, 4a, 4b**	**Config 1b**	**Config 2d, 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 (EPS Operator 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.								
	✓		✓		✓	✓	✓	✓

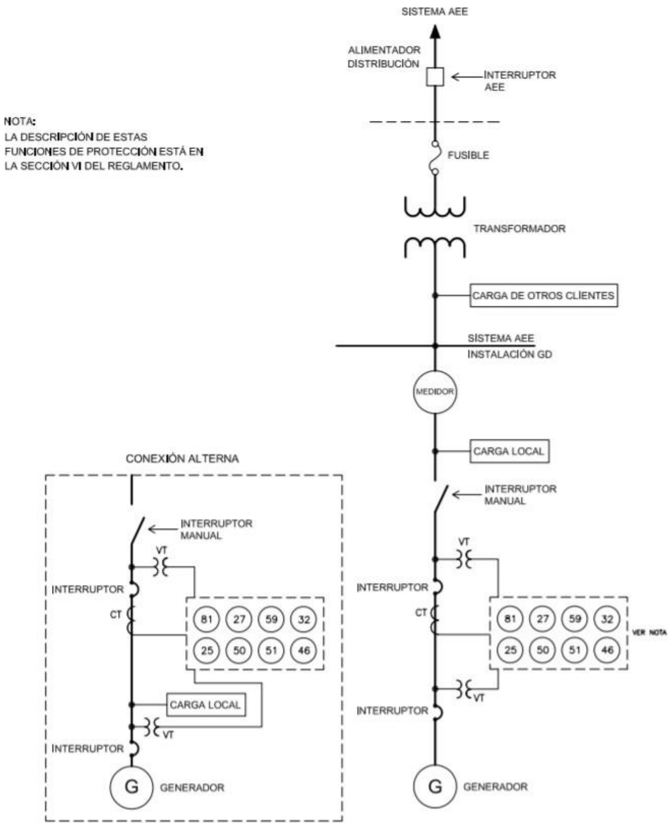
Appendix D: Typical One-Line Diagrams

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.

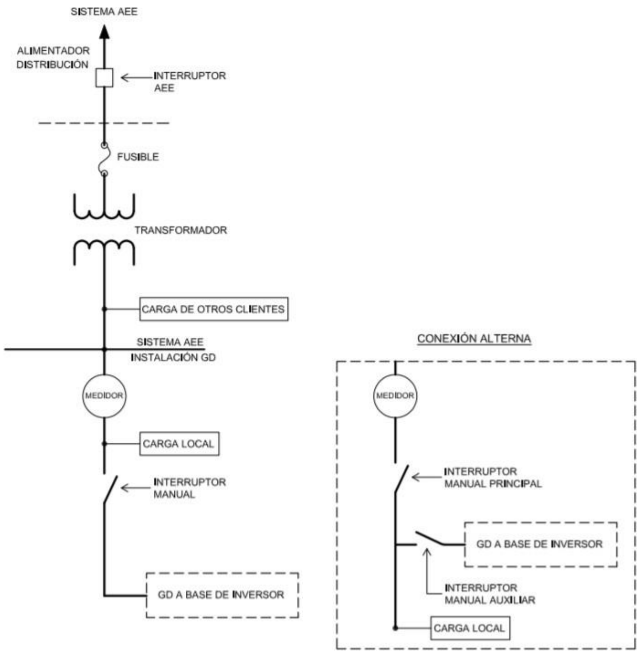
1.1. Diagram 1 – Synchronous Generator Connected to the Primary Distribution Network



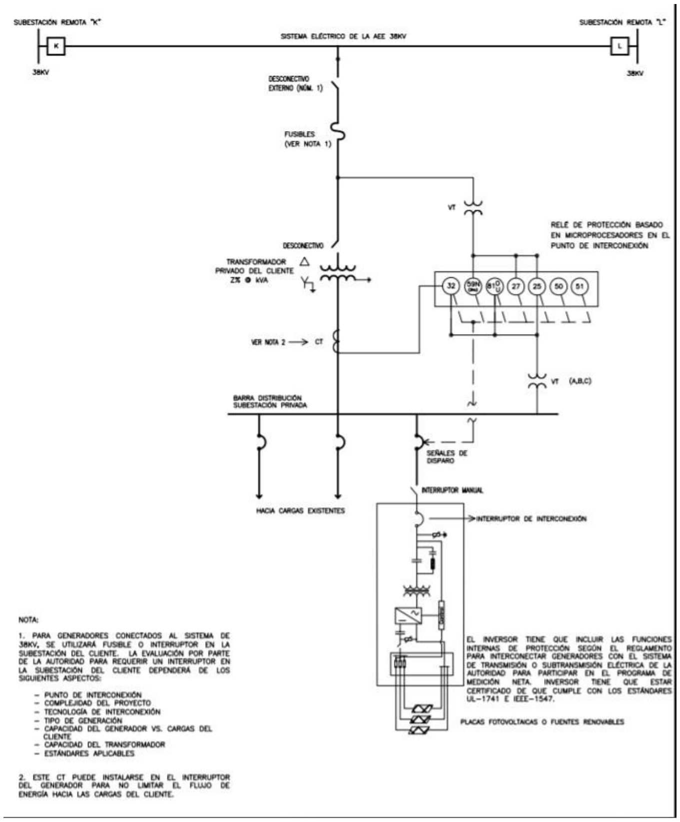
1.2. Diagram 2 – Synchronous Generator Connected to the Secondary Distribution Network



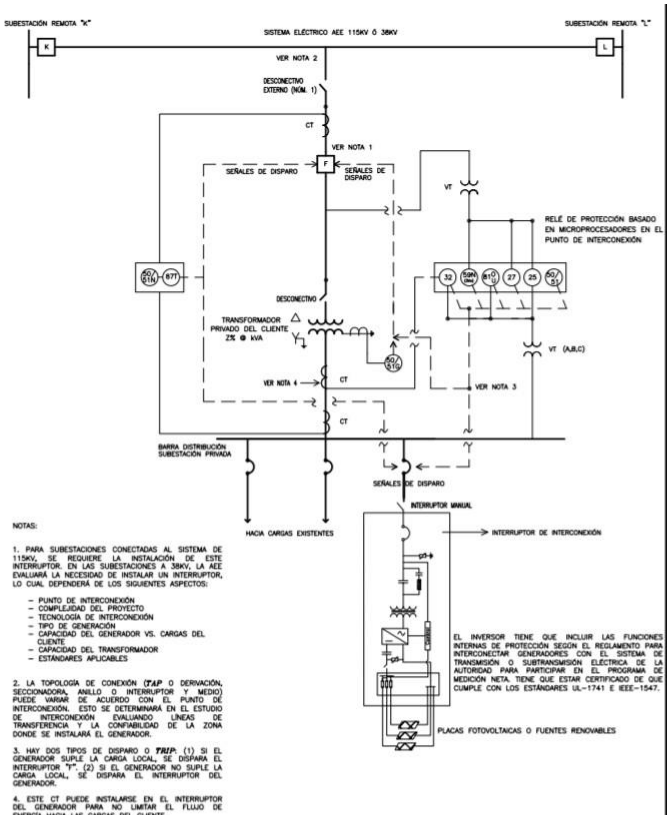
1.3. Diagram 3 – Connection of inverter-based DER to the Secondary Distribution Network



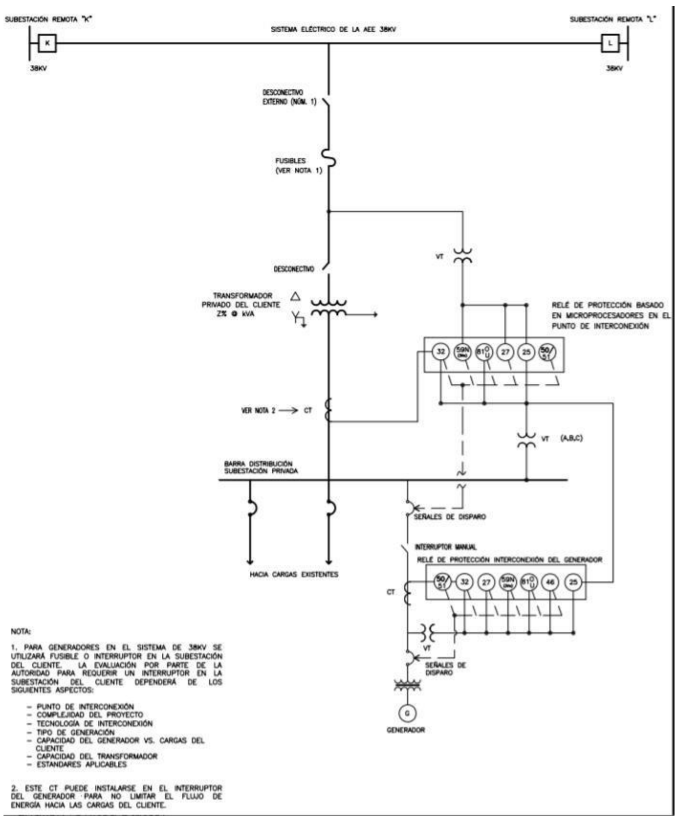
1.4. Diagram 4 – Connection of an inverter to the sub-transmission network (38kV) through fuses



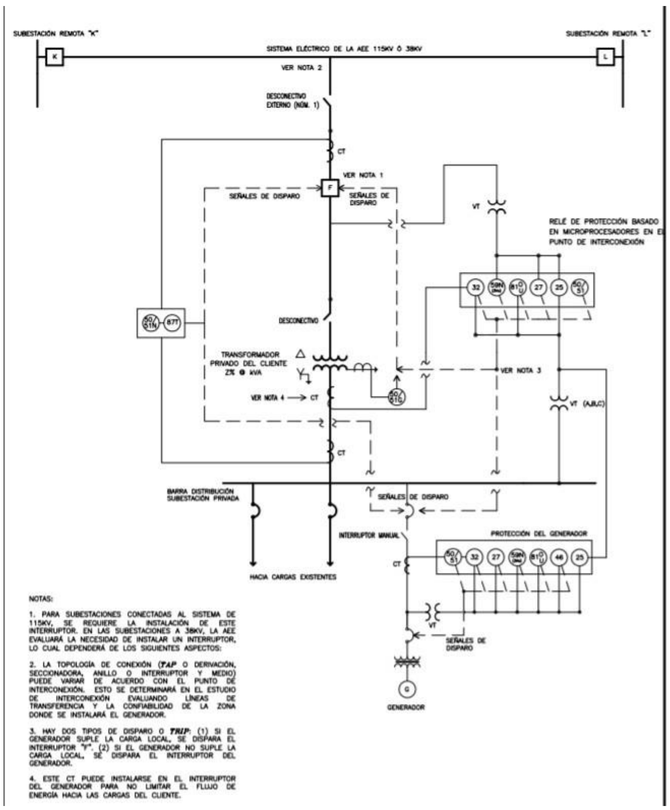
1.5. Diagram 5 - Connection of an inverter to the transmission (115kV) or sub-transmission network (38kV) through switches



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 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 DER 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
· Time/Inst. Over Current or High Side Fuse (38kV and below)	· Transformer Differential · Fault Pressure · Time/Inst. Over Current

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1.9. Interconnection Feeder Protection

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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)

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100kV and above	· Line protection schemes will follow the C37.113 IEEE guide for Protective Relay Applications to Transmission Lines and best engineering practices. The scheme selected will depend on available communication paths between the terminals, topology of the system, Source-Impedance Ratio (SIR) and short-circuit fault current magnitude levels, as well as any applicable existing line relaying scheme at the remote end(s). The prefer scheme(s) will be line differential due to its simplicity and straight forward application as a high-speed communication assisted scheme. Any permissive over/under- reaching or blocking schemes will be evaluated, as applicable, on a case-by-case basis, and as a standard practice, both primary and backup schemes must be high-speed, with backup Step-distance and overcurrent protection programmed. · The step distance impedance elements application must consider Infeed in case multiple lines exists outside of the generating facility, and the effect of mutual-couplings if lines shared same right-o-way. The definite time-delay for the impedance elements should coordinate with remote(s) outgoing lines protection and typical acceptable delays are in between 18-24 cycles. For the phase and ground overcurrent's element these must be set based on acceptable contingencies for generation and/or transmission lines and maintain coordination with remote terminals outgoing existing overcurrent protection with a recommended minimal typical acceptable time-coordination margins of 18-24 cycles.

1.10. EPS Operator's Islanding Prevention Schemes

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- 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

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- 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 protections functions. However, a second multi-function relay is necessary to provide for a relay failure.
- The DER 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**
· 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

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Appendix F: Commissioning Checklist

Steps		Subject	Notes	Completed? Yes	Completed? No	Completed? N/A	Date
1		Date notification is received 10 days before test.		Completed ☐			
2		Inspector Assignment		Completed ☐			
3		Document Validation					
	3.1	Short Circuit Study and Coordination of Protection Settings is received	Required if capacity is equal to or greater than 500 kW (10 days before inspection)	☐	☐	☐	
	3.2	Private Inspector Inspection Report		☐	☐	☐	
	3.3	Evidence of Installer Certificate by OPPPE.		☐	☐	☐	
	3.4	System certification issued by OGPe		☐	☐	☐	
4		Field Inspection		Completed ☐			
5		Deficiencies Notification to contractor, if any.		Completed ☐			
6		System installer submits Electrical Certification		Completed ☐			
7		Approve the Electrical Installation Certification by Licensed Engineer or Master Electrician		Completed ☐			
	7.1	Must be signed by Licensed Engineer or Master Electrician with respective seals or stamps. Verify equipment and information in Certification matches request.	Confirm approval by Inspector	☐	☐	☐	
	7.2	Certification of Tests carried out by an engineer (Annex F)	Signed and Sealed	☐	☐	☐	
	7.3	Settings Print Screen or Manufacturing Certification		☐	☐	☐	
		Frequency Requirements	Under Frequency FAST: 57.5 Hz = 10s/10000ms	☐	☐	☐	
			Under Frequency SLOW: 59.2 Hz = 300000ms/300s/5min	☐	☐	☐	
			Over Frequency SLOW: 60.5 Hz = 300000ms/300s/5min	☐	☐	☐	

			Over Frequency FAST: 61.5 Hz = 10s/10000ms	☐ ☐ ☐	
		Voltage Requirements	Under Voltage FAST: 54v / 108v / 124v = 0.16s/160ms	☐ ☐ ☐	
			Under Voltage MID: 72v / 144v / 166.2v= 1s/1000ms	☐ ☐ ☐	
			Under Voltage SLOW: 205.6v / 211.2v / 243.6v = 2s/2000ms	☐ ☐ ☐	
			Over Voltage SLOW: 132v / 264v / 304.7v = 1s/1000ms	☐ ☐ ☐	
			Over Voltage FAST: 144v / 288v / 332.4v = 0.16s/160ms	☐ ☐ ☐	
8	Documents Verification			☐ Completed	
	8.1	Insurance Exemption Agreement or Public Liability Insurance is generated		☐ ☐ ☐	
	8.2	Indicate if it is a Primary or Secondary Account		☐ ☐ ☐	
9		Project Approval		☐ Completed	

Appendix G: Telemetry Options (to be determined when transfer trip not required)

Communication Options for Plants ≥ 2 MW

Type	Benefits	Risk	Costs	Timing
Fiber - EPS Operator installed	- Ensure scope, cost, and schedule	- Higher costs	- Included in Study estimates	Per EPS Operator construction schedule
	- Highly reliable x5 - 9's	- Required to run fiber to substation		
		- Single spur is less reliable		

Appendix H: Smart Inverter Setting Sheets

1. Required Smart Inverter Functions

Smart Inverters must be (a) set to conform to the default setting requirements and (b) capable of performing the default functions, both provided in this document, “Smart Inverter Settings Sheets”, as applicable. The requirements contained in this document are applicable to all sizes and types of inverter-based generation. The 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.

While customers must ensure compliance with the requirements set forth in this “Smart Inverter Settings Sheets”, the interconnection agreement may require settings and functions overriding the default settings requirements and functions provided in this document. Notwithstanding the preceding provisions of this “Smart Inverter Settings Sheets”, customer’s Smart Inverter(s) shall conform with the requirements and functions required pursuant to interconnection agreement.

1.1 Communication Requirements

Table 0-1 lists minimum communication requirements for Smart Inverters connected to the distribution system.

Table 0-1- Minimum Requirements for Communication and Interface

Protocol	Transport	Physical Interface/Layer
IEEE 1815 (DNP3)/ SunSpec Modbus/ IEEE 2030.5 (Sep 2.0)	TCP/IP	Ethernet/ RS 485

1.2 Control Modes

Table 1-2 lists control modes that must be supported by Smart Inverters as well as default status of each control mode.

Table 0-2- Smart Inverter Control Modes

Applicable to Retail Customers Interconnected after the publication date of this document version.			
Mode of Operation	**Required/Optional**	**Description**	**Default Activation Status**
Anti-Islanding	Required	Refers to the ability to detect loss of utility source and cease to energize	Activated
Adjustable constant power factor	Required	Refers to Power Factor set to a fixed value.	Deactivated
Adjustable Constant Reactive Power	Required	Refers to Reactive Power set to a fixed value	Deactivated

Voltage Ride through	Required	Refers to ability of Smart Inverter to ride through a certain range of voltages before tripping off	Activated
Frequency Ride through	Required	Refers to ability of Smart Inverter to ride through a certain range of frequencies before tripping off	Activated
Voltage – Reactive (Volt/Var)	Required	Refers to control of reactive power output as a function of voltage	Activated
Voltage – Active Power (Volt/Watt)	Required	Refers to control of real power output as a function of voltage	Activated
Frequency - Watt	Required	Refers to control of real power as a function of frequency	Deactivated
Ramp Rates	Required	Refers to ability to have an adjustable entry service ramp rate when a DER restores output of active power or changes output levels over the normal course of operation.	Activated

2. Smart Inverter Function Settings

This section lists the required settings for smart inverter functions.

2.1 Anti-Islanding Settings

Smart Inverters shall detect the unintentional island and trip as specified in Table 0-3.

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Table 0-3- Responses to Islanding and Open Phase Conditions - ACTIVATED

Applicable to Retail Customers Interconnected	
Condition	**Maximum Trip Time (s)**
Islanding/Open Phase	2

2.2 Voltage Settings

2.2.1 Voltage Trip Settings

Smart Inverters shall meet the abnormal voltage response requirements, as specified in Table 0-4.

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Table 0-4- Smart Inverter Response to Abnormal Voltage

Voltage Trip Settings	Default Voltage (pu)	Adjustable Range for Voltage (pu)	Default Trip/Clearing Time (s)	Adjustable Range for Trip Time (s)
Over Voltage 2 (OV2)	V ≥ 1.2	0.16	Fixed at 1.2	Fixed at 0.16

Over Voltage 1 (OV1)	V ≥ 1.1	1.1 - 1.2	13	1 - 13
Under Voltage 1 (UV1)	V ≤ 0.88	0 - 0.88	21	11 - 50
Under Voltage 2 (UV2)	V ≤ 0.5	0 - 0.5	2	2 - 21

2.2.2 Voltage Ride Through Settings

Smart Inverters shall meet the Low/High Voltage Ride-Through requirements, as specified in Table 0-5.

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Table 0-5- Low/High Voltage Ride-Through Minimum Requirement – ACTIVATED

Voltage Ride-Through Settings	Voltage Range (pu)	Smart Inverter Response (Operating Mode)	Maximum Response Time (s)	Minimum Ride Through Time (s)
High Voltage 2 (HV2)	V ≥ 1.2	Cease to Energize	0.16	N/A
High Voltage 1 (HV1)	1.1 ≤ V ≤ 1.2	Momentary Cessation	0.083	12
Near Normal Voltage (NNV)	0.88 ≤ V ≤ 1.1	Continuous Operation	N/A	Infinite
Low Voltage 1 (LV1)	0.7 ≤ V ≤ 0.88	Mandatory Operation	N/A	20
Low Voltage 2 (LV2)	0.5 ≤ V ≤ 0.7	Mandatory Operation	N/A	10
Low Voltage 3 (LV3)	V ≤ 0.5	Momentary Cessation	0.083	1

2.3 Frequency Settings

2.3.1 Frequency Trip Settings

Smart Inverters shall meet the abnormal frequency response requirements, as specified in Table 0-6.

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Table 0-6- Smart Inverter Response to Abnormal Frequency

Frequency Trip Settings	Default Frequency (Hz)	Adjustable Range for OF1 (Hz)	Default Trip/Clearing Time (s)	Adjustable Range for Trip Time (s)
Over Frequency 2 (OF2)	f ≥ 62	61.8 - 66	0.16	0.16 - 1000
Over Frequency 1 (OF1)	f ≥ 61.2	61.2 - 66	300	21 - 1000
Under Frequency 1 (UF1)	f ≤ 58.8	50 - 58.8	300	21 - 1000
Under Frequency 2 (UF2)	f ≤ 57	50 - 57	0.16	-1000

2.3.2 Frequency Ride-Through Settings

Smart Inverters shall meet the Low/High Frequency Ride-Through requirements, as specified in Table 0-7.

Table 0-7- Low/High Frequency Ride-Through Minimum Requirement – ACTIVATED

Frequency Ride-Through Settings	High Frequency Range (Hz)	High Smart Inverter Response (Operating Mode)	Minimum Ride Through Time (s)
High Frequency 2 (HF2)	f ≥ 62	N/A	N/A
High Frequency 1 (HF1)	61.2 ≤ f ≤ 62	Mandatory Operation	299
Near Normal Frequency (NNF)	58.8 ≤ f ≤ 61.2	Continuous Operation	Infinite
Low Frequency 1 (LF1)	57 ≤ f ≤ 58.8	Mandatory Operation	299
Low Frequency 2 (LF2)	f ≤ 57	N/A	N/A

2.4 Voltage-Reactive Power Control Mode Settings

An example Volt-Var characteristic is shown in Figure 0-1. The voltage-reactive power characteristic shall be configured in accordance with the default parameter values specified in Table 0-8.

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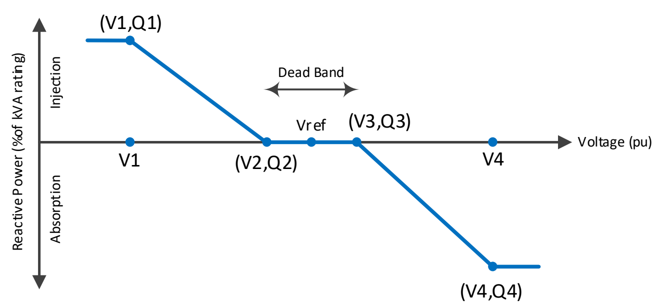

Figure 0-1. Example Volt-Var characteristic

Table 0-8- Volt-Var Settings – ACTIVATED

Volt-Var Parameters	Definitions	Default Values (% of nominal rating)	Allowable Range	
			Minimum	Maximum
Vref	Dead band center	VN	95% VN	105% VN
V2	Dead band lower voltage limit	98% VN	Vref – 3%VN	Vref

Q2	Reactive power injection or absorption at voltage V2	0	maximum reactive power capability, absorption	maximum reactive power capability, injection
V3	Dead band upper voltage limit	102% VN	Vref	Vref + 3%VN
Q3	Reactive power injection or absorption at voltage V3	0	maximum reactive power capability, absorption	maximum reactive power capability, injection
V1	Voltage at which DER shall inject Q1 reactive power	92% VN	Vref – 18%VN	V2 – 2%VN
Q1[(1)]	Reactive power injection at voltage V1	44%	0	maximum reactive power capability, injection
V4	Voltage at which DER shall absorb Q4 reactive power	108% VN	V3 + 2%VN	Vref + 18%VN
Q4[(1)]	Reactive power absorption at voltage V4	44%	maximum reactive power capability, absorption	0
Open loop response time	Time to 90% of the reactive power change in response to the change in voltage	5 sec	1 sec	90 sec

[(1)] This requires that the Smart Inverter operates with a reactive power priority and generate/absorb reactive power to the ranges specified in this table irrespective of active power production.

2.5 Voltage-Active Power Control Mode Settings

Two examples of these characteristics are shown in Figure 0-2. The characteristic shall be configured in accordance with the default parameter values specified in Table 0-9.

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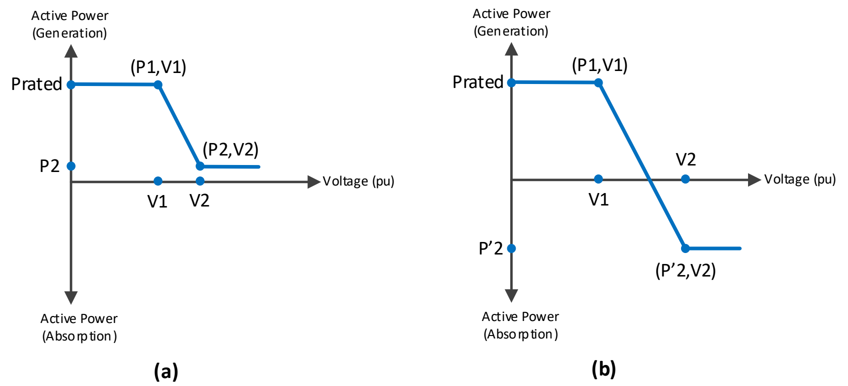

Figure 0-2. Example Volt-Watt characteristics

Table 0-9- Volt-Watt Settings – ACTIVATED

Voltage-active power parameters	Default Settings	Ranges of allowable settings	
		Minimum	Maximum
V1	106% VN	105% VN	109% VN
P1	P_{RATED}	NA	NA
V2	110% VN	V1 + 1% VN	110% VN
P2 (applicable to DER that can only generate active power)	The lesser of 0.2 P_{RATED} or P_{MIN}(1)	P_{MIN}	P_{RATED}
P'2 (applicable to DER that can generate and absorb active power)	0	0	P'_{RATED}(2)
Open-loop response time	10 sec	0.5 sec	60 sec

(1) P_{MIN} is the minimum active power output in p.u. of the DER rating (i.e., 1.0 p.u.).
(2) P'_{RATED} is the maximum amount of active power that can be absorbed by the DER.

2.6 Ramp Rate Settings

The following is the ramp-rate requirement during normal and reconnection operation of Smart Inverters:

- Normal ramp-up rate: For transitions between energy output levels over the normal course of operation, the default value is 100% of maximum current output per second with a range of adjustment between 1% to 100%.
- Connect/Reconnect Ramp-up rate: Upon starting power into the grid, following a period of inactivity or a disconnection, the inverter shall wait for 300 seconds before reconnecting and shall be able to control its rate of increase of power from 1 to 100% maximum current per second. The default value is 2% of maximum current output per second. The maximum active power step during restoring output is 20%

Appendix I: Generator Interconnection Application

(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 Generating Facility or 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 Generating Facility or 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: ______________________________

Microgrid Information[7]:

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).

*Aggregate Generator Nameplate kV*AR: ___________.

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

Typical Reactive Load (if known):________________

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

Maximum Physical Export Capability Requested: ______________ kW

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

Equipment Type	Certifying Entity
6. ______________________________	______________________________
7. ______________________________	______________________________
8. ______________________________	______________________________
9. ______________________________	______________________________
10. ______________________________	______________________________

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.

Generating Facility Characteristic Data (for inverter-based machines)

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
7. ______________________	_______	_______
8. ______________________	_______	_______
9. ______________________	_______	_______
10. ______________________	_______	_______
11. ______________________	_______	_______
12. ______________________	_______	_______

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.
    - 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[8] 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

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: ___________

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

Appendix J: Simplified Interconnection Application and Agreement

To be developed in the future

Appendix K: 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 set forth in the TIR (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.

Appendix L: Feasibility Study Agreement

To be developed in the future

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Appendix M: System Impact Studies (to be used for Transmission and Distribution Cases)

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 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 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:

Appendix N: Facilities Study Agreement (to be used for Transmission and Distribution Cases)

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:

1.0 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.

2.0 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.

3.0 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.

4.0 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.

5.0 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.

6.0 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.

7.0 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.

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

9.0 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.

10.0 Waiver.

10.1. 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.

10.2. 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.

11.0 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.

12.0 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.

13.0 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.

14.0 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.

14.1. 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.

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

15.0 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)[9]:

____

Number of third-party easements required for transmission lines[10]:

____

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: ______________________

[9] To be completed in coordination with PREPA.

[10] *Id.*

Appendix O: Interconnection Agreement

To be developed in the future

Appendix P: Agreement for Participation in the Shared Net Metering Program

To be developed in the future

Exhibit B

GOVERNMENT OF PUERTO RICO

Public Service Regulatory Board

Puerto Rico Energy Bureau

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Version revised by LUMA on 11/15/21 and including LUMA's Proposed Additional Revisions on 11/1/22

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Generating Facility and Microgrid Interconnection Regulation

NEGOCIADO DE ENERGÍA DE PUERTO RICO

NEPR

JUNTA REGLAMENTADORA DE SERVICIO PÚBLICO

TABLE OF CONTENTS

Commented [A1]: In addition to the original proposal of removing Attachments 3 (Codes and Standards) and Attachment 4 (Certification of Equipment) (listed at the end this Table of Contents), LUMA also proposes removing all other Attachments and incorporating these into the separate Technical Interconnections Requirements (TIR) document, to facilitate the process of performing any necessary or suitable revisions or updates to these documents in the future, while remaining subject to Energy Bureau approval.

~~ATTACHMENT 1 GENERATOR INTERCONNECTION APPLICATION~~

~~ATTACHMENT 2 SIMPLIFIED INTERCONNECTION APPLICATION AND AGREEMENT~~

~~ATTACHMENT 3 CERTIFICATION CODES AND STANDARDS~~

~~ATTACHMENT 4 CERTIFICATION OF GENERATOR EQUIPMENT PACKAGES~~

~~ATTACHMENT 5 FEASIBILITY STUDY AGREEMENT~~

~~ATTACHMENT 6 SYSTEM IMPACT STUDY AGREEMENT~~

~~ATTACHMENT 7 FACILITIES STUDY AGREEMENT~~

~~ATTACHMENT 8 INTERCONNECTION AGREEMENT~~

~~ATTACHMENT 9 AGREEMENT FOR PARTICIPATION IN THE SHARED NET METERING PROGRAM~~

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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.

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]: 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. In addition, LUMA proposes including in this Technical Interconnection Requirements document all Annexes to this Regulation to facilitate the process of performing any necessary or suitable revisions or updates to these documents in the future, while remaining subject to Energy Bureau approval.

Commented [A3]: 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 1.47Section 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 1.27Section 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 between the Interconnection Customer and the EPS Operator governing the

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interconnection of the Generating Facility or Mictrogrid to the Electric Power System described in Section 1.36, the form of which shall be included ~~provided~~ in ~~Attachment 8~~ ~~to this Regulation~~ the Technical Interconnection Requirements (TIR) document.

(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.

Commented [A4]: LUMA now proposes to have this Attachment 8 removed from this Regulation and incorporated into the TIR which will facilitate future necessary or suitable revisions or updates to this document while still being subject to Energy Bureau approval.

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(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 1.47Section 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 1.47Section 5.12~~1.47 and Section 1.47.A~~Section 1.47.ASection 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.

Cnet = kWhcon – kWhexp – 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 1.47~~~~Section 5.12~~1.47 and Section 1.47.A~~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 1.22Section 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 1.27.CSection 3.01~~1.27.~~C~~ and a sample form of the Simplified Interconnection Application and Agreement shall be included in the TIR~~is found in ATTACHMENT 2~~. The Simplified Process uses the Fast Track screens found in Section 1.28.B~~Section 1.28.BSection 3.02~~1.28.~~B~~ with a more expedited timeline, as described in Section 1.28.A(1)~~Section 1.28.A(1)Section 3.02~~1.28.~~A(1)~~, and simplified testing requirements, as described in Section 1.41.D~~Section 1.41.DSection 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

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Commented [A5]: LUMA now proposes to have this Attachment 2 removed from this Regulation and incorporated into the TIR which will facilitate future necessary or suitable revisions or updates to this document while still being subject to Energy Bureau approval.

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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 [A6]: 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 [A7]: 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 1.27.C~~~~Section 3.01~~1.27.~~C~~. Both the Simplified Process and the Fast Track Process use the screens found in Section 1.28.B~~Section 1.28.B~~~~Section 3.02~~1.28.~~B~~, however the Simplified Process expedites the screening timeline, as described in Section 1.28.A(1)~~Section 1.28.A(1)~~~~Section~~

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

~~3.02~~1.28.A(1) and relies on a combined application and agreement , to be included in the TIR~~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 1.27.ASection 3.01~~1.27.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 1.27Section 3.01~~1.27, or does not pass the Fast Track Process, shall be evaluated under the Study Process in ~~Article 4.~~Article 4. The Study Process 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 1.37Section 5.02~~1.37.

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.

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.

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Commented [A8]: As mentioned, LUMA now proposes to have this Attachment 2 removed from this Regulation and incorporated into the TIR which will facilitate future necessary or suitable revisions or updates to this document while still being subject to Energy Bureau approval.

Commented [A9]: 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.

Commented [A10]: 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

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 1.21Section 2.04~~1.21, 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 1.22.GSection 2.05~~1.22.~~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 1.22.ESection 2.05~~1.22.~~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:

Commented [A11]: 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 [A12]: This is a new report and process that will take time to develop and integrate with the Portal's architecture and broader IT system.

(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.);

(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 1.22.H~~~~Section 2.05~~1.22~~.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 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 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 EPS Operator shall include a form for the Interconnection Application and the Simplified Interconnection Application and Agreement in the TIR document. ~~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.~~

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.

Commented [A13]: 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.

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Commented [A14]: To further facilitate the implementation of the foregoing comment, LUMA proposes that Attachments 1 and 2 be incorporated in the TIR document, which will be subject to the Energy Bureau's approval and will facilitate future necessary or suitable revisions or updates, with the clarification that the documents shall cover content but not specify form or formatting as Attachment 1 currently appears to be made for paper / pdf Application, not digital.

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 [A15]: 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 1.23Section 2.061.23~~, Section 1.24~~Section 1.24Section 2.071.24~~, and Section 1.25~~Section 1.25Section 2.081.25~~, 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 1.27Section 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 1.28Section 3.021.28~~ or the supplemental review screens in Section 1.30~~Section 1.30Section 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 1.27.ASection 3.011.27.A~~ and the smaller size requirements for the Simplified Process found in Section 1.27.C~~Section 1.27.CSection 3.011.27.C~~. Both the Simplified Process and the Fast Track Process use the screens found in Section 1.28.B~~Section 1.28.BSection 3.021.28.B~~, however the Simplified Process expedites the screening timeline, as described in Section 1.28.A(1)~~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 1.28.A(1)Section 3.02~~1.28~~.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 in the TIR ~~of Attachment 4)~~; and

(5) Has an Nameplate Rating under the thresholds found in Table 1~~Table 1Table 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 1.27Section 3.01~~1.27, 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

Commented [A16]: LUMA proposed incorporating these requirements (of Attachment 4) in the TIR.

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Commented [A17]: These limits might be changed, pending additional revision of Technical Interconnection Requirements document.

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Commented [A18]: 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.

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 1.27.ASection 3.01~~1.27.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 1.28.A(1)Section 3.02~~1.28.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 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~~.

~~(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~~

Commented [A19]: 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.

~~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 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.

Commented [A20]: The criteria referenced in the table below might change, as the TIR is updated and completed.

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~~

~~[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.~~

~~Primary Distribution Line Type~~	~~Type of Interconnection~~	~~Result/Criteria~~
~~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 (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~~

Commented [A21]: 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.

~~(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 8Attachment 8~~.

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(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 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 1.35Section 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 1.29Section 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 1.30Section 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~~s 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 1.30.DSection 3.04~~~~1.30.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

Commented [A22]: LUMA proposes eliminating the concept of average of days in this instance as it is not an applicable concept in the context.

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screening requirements of Section 1.30.C(1)~~Section 1.30.C(1)Section 3.04~~1.30.~~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 1.47Section 5.12~~1.47.

(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 [A23]: 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

~~[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.

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 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 1.30.CSection 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 1.30.CSection 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 1.30.CSection 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 1.35Section 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~~0Article 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).~~ , the form of which shall be included by the EPS Operator in the TIR document (the "Feasibility Study Agreement").

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 F~~f~~easibility S~~s~~tudy A~~a~~greement 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 will be ~~are~~ described in the ~~attached~~ "F~~f~~easibility S~~s~~tudy A~~a~~greement ~~(ATTACHMENT 5)~~. The F~~f~~easibility S~~s~~tudy A~~a~~greement 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 the ~~certain~~ technical data identified in ~~(ATTACHMENT A) to~~ the Feasibility Study Agreement ~~(ATTACHMENT 5)~~. The EPS Operator ~~may require a deposit~~ ~~will be~~ may require the Interconnection Customer ~~d~~ 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~~, and a true ~~up~~ cost will be done at the ~~Interconnection Customer~~end of the study.

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Commented [A24]: LUMA now proposes to have this Attachment 5 removed from this Regulation and incorporated into the TIR which will facilitate future necessary or suitable revisions or updates to this document while still being subject to Energy Bureau approval.

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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 F~~f~~easibility S~~s~~tudy A~~a~~greement 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 1.47Section 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

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

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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 1.47Section 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 as per the form provided in the TIR document ~~(ATTACHMENT 6)~~ ("System Impact Study Agreement") 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 S~~s~~ystem I~~i~~mpact S~~s~~tudy A~~a~~greement ~~(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 shall be ~~are~~ described in ~~the attached~~ S~~s~~ystem I~~i~~mpact S~~s~~tudy

A~~a~~greement. The EPS Operator may require the Interconnection Customer to make a deposit or an upfront full payment of the good faith estimated costs of the study, which deposit or upfront payment~~, A deposit of the good faith estimated costs for each system impact study~~ shall be provided by the Interconnection Customer when it returns to the EPS Operator the System Impact S~~s~~tudy A~~a~~greement~~s~~ executed by Customer, and a true up cost will be done when the study is completed and delivered to the Interconnection Customer. The Interconnection Customer will be responsible for the actual costs of the study.

D. To remain in consideration for interconnection, an Interconnection Customer who has requested a system impact study must return the executed S~~s~~ystem I~~i~~mpact S~~s~~tudy A~~a~~greement and pay the required study deposit or upfront payment ~~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 S~~s~~ystem I~~i~~mpact S~~s~~tudy A~~a~~greement 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.

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~~(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, the form of which shall be included by the EPS Operator in the TIR document ("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. The Interconnection Customer will be responsible for the actual costs of this study. The EPS Operator may require the Interconnection Customer to make a deposit or an upfront full payment of the good faith estimated costs of the study, which deposit or upfront payment shall be provided by the Interconnection Customer when it returns to the EPS Operator the Transmission System Impact Study Agreement executed by Customer, and a true up cost will be done when the study is completed and delivered to the Interconnection Customer.

G. To remain in consideration for interconnection, an Interconnection Customer must return the executed Transmission System I~~i~~mpact S~~s~~tudy A~~a~~greement 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 I~~i~~mpact S~~s~~tudy A~~a~~greement is signed by the Parties.

SECTION 1.35. Facilities Study

A. The EPS Operator shall provide the Interconnection Customer a facilities study agreement the form of which shall be included by the EPS Operator in the TIR ("Facilities Studies 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.

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Commented [A27]: Although not currently included as an Attachment to this Regulation, LUMA proposes to have this document incorporated into the TIR which will facilitate future necessary or suitable revisions or updates to this document while still being subject to Energy Bureau approval

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(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 F~~f~~acilities S~~s~~tudy A~~a~~greement 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 shall be ~~are~~ described in the ~~attached~~ F~~f~~acilities S~~s~~tudy A~~a~~greement. ~~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.~~ The EPS Operator may require the Interconnection Customer to make a deposit or an upfront full payment of the good faith estimated costs of this study, which deposit or upfront payment shall be provided by the Interconnection Customer when it returns to the EPS Operator the Facilities Study Agreement executed by the Interconnection Customer, and a true up cost will be done when the study is completed and final and delivered to the Interconnection Customer. The Interconnection Customer will be responsible for the actual costs of the study.

C. To remain under consideration for interconnection, the Interconnection Customer must return the executed F~~f~~acilities S~~s~~tudy A~~a~~greement and pay the required study deposit or upfront payment 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 F~~f~~acilities S~~s~~tudy A~~a~~greement. 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

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receiving the executed F~~f~~acilities S~~s~~tudy A~~a~~greement. 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 1.47Section 5.12~~1.47, uses devices tested to national standards, or is approved by the EPS Operator. The facilities study shall identify:

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(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 F~~f~~acilities S~~s~~tudy A~~a~~greement.

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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 1.37Section 5.02~~1.37, 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 [A31]: 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 or Generating Facility 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 1.39Section 5.04~~1.39, Section 1.41~~Section 1.41Section 5.06~~1.41, Section 1.42~~Section 1.42Section 5.07~~1.42, Section 1.46~~Section 1.46Section 5.11~~1.46 ~~and Article 6.~~ and Article 6.

~~G.~~H. The form for the Interconnection Agreement shall be included in the TIR document.

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 1.35Section 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 1.36Section 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

Commented [A32]: For further clarity, reference to "Generating Facility" should be included here given that this Section applies to all types of Interconnecting Applications.

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granted absent a Force Majeure Event or other similarly extraordinary circumstances.

~~SECTION 1.39. Interconnection Metering and Telemetry~~

~~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

Commented [A34]: 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.

Commented [A35]: This section will be eliminated in later revisions, as it will be referenced in the TIR. [See TIR, Section 10, Plant Revenue Metering] 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] If PREPA is the EPS Operator, the Interconnection Customer shall notify the PREPA Office of Inspections in the appropriate region.

(7) Operational and protection settings;

(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 accordance with~~in~~ the Interconnection Agreement, ~~t~~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 1.47Section 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 1.47Section 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 1.47Section 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 1.47Section 5.12~~1.47, 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.

[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.

(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.

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 shall include the application and agreement forms indicated in this Regulation. 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

Commented [A36]: [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.

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

~~E.~~F. For Microgrids, the technical requirements of Section 1.50~~Section 1.50Section 6.03~~1.50, Section 1.52~~Section 1.52Section 6.05~~1.52 and Section 1.53~~Section 1.53Section 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~~

Commented [A38]: [See TIR Sec 7 Protection Coordination Requirements, Art 7.2 Unintended 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~~

Commented [A39]: [See TIR Sec 7 Protection Coordination Requirements, Art 7.2 Unintended Island Detection and Section 13 Microgrids (TBD)]

~~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 1.50~~Section 1.50~~Section 6.03~~1.50.~~

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~~(2) As an alternative to Trip in response to voltage disturbances as required by~~ Section 1.52.B~~Section 1.52.B~~Section 6.05~~1.52.B.~~

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[9] Disconnection implies isolation.

~~(3) As an alternative to Trip in response to frequency disturbances as required by~~ Section 1.52.C~~Section 1.52.CSection 6.05~~1.52.C~~.~~

~~(4) When issued a planned Island request by the EPS Operator, and shall meet the criteria of either~~ Section 1.51~~Section 1.51Section 6.04~~1.51 ~~B(1) or B(2).~~

~~(5) When Paralleling a Microgrid to the EPS, the Enter Service and synchronization requirements of~~ Section 1.53~~Section 1.53Section 6.06~~1.53 ~~shall be met.~~

~~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~~

~~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~~

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

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Commented [A40]: [See TIR Section 6 DER Response to Abnormal Conditions. Arts. 6.4 & 6.5 Voltage/Frequency Trip and RT Requirements]

~~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 1.53Section 1.53Section 6.061.53 ~~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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~~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 2Table 2Table 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 3Table 3Table 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)~~

[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.

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

Commented [A41]: [See TIR Section 5 General Technical Requirements, Arts. 5.10 5.10.1 Enter Service & 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 5Table 5** below. The synchronization limits stated in **Table 5Table 5Table 5** below may be waived by the EPS Operator if Paralleling does not exceed the rapid voltage change requirements of Section 1.54Section 1.54Section 6.071.54 nor applicable flicker requirements.

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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~~

~~SECTION 1.54. Limitation of rapid voltage changes~~

Commented [A42]: [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 [A43]: [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 [A44]: [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 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~~

Commented [A45]: [See TIR, Section 4 General Technical Requirements, Art 4.2 Isolation Device]

~~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, 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 [A46]: [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.

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

(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.

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 the form of which shall be included by the EPS Operator in the TIR. ~~(see Attachment 9)~~.

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Commented [A47]: LUMA now proposes to have this agreement (proposed in this Regulation as Attachment 9) removed from this Regulation and incorporated into the TIR which will facilitate future necessary or suitable revisions or updates to this document while still being subject to Energy Bureau approval.

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 1.43Section 5.081.43~~ 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 1.26Section 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

Commented [A48]: 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.

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

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

(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 Generating Facility or 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 Generating Facility or 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):________________________________

____.

Commented [A49]: LUMA continues to review these attachments and notes that certain attachments are missing (Attachment 2, 5, 8 and 9)

Commented [A50R49]: LUMA now proposes to have this Attachment 1 removed from this Regulation and incorporated into the TIR which will facilitate future necessary or suitable revisions or updates to this document while still being subject to Energy Bureau approval. LUMA will include this form with the proposed revisions below in a revised version of the its proposed Comprehensive TIR document.

Commented [A51]: LUMA proposes this revision to clarify that this fee also applies to Generating Facilities, not just Microgrids, given that the Interconnection Application applies to all types of facilities.

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Commented [A52]: LUMA proposes this revision to clarify that this fee also applies to Generating Facilities, not just Microgrids, given that the Interconnection Application applies to all types of facilities.

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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: _________________________

Microgrid Information[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

Commented [A53]: LUMA proposes to have this Attachment 2 removed from this Regulation and incorporated into the TIR which will facilitate future necessary or suitable revisions or updates to this document while still being subject to Energy Bureau approval.

~~ATTACHMENT 3~~

~~CERTIFICATION CODES AND STANDARDS~~

Commented [A54]: We have marked this entire document as deleted as per the previous comment below.

Commented [A55]: 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 set forth in the TIR ~~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.

Commented [A56]: It is clarified that LUMA had proposed removing this attachment and addressing these requirements in the TIR document.

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Commented [A57]: As mentioned, LUMA had proposed removing Attachment 3 and addressing its requirements in the TIR document.

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~~ATTACHMENT 5~~

FEASIBILITY STUDY AGREEMENT

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~~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

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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: ____________________

<u>Attachment A to System Impact Study Agreement</u>

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

Commented [A60]: LUMA now proposes to have this Attachment 7 removed from this Regulation and incorporated into the TIR which will facilitate future necessary or suitable revisions or updates to this document while still being subject to Energy Bureau approval.

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

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~~ATTACHMENT 9~~

AGREEMENT FOR PARTICIPATION IN THE SHARED NET METERING PROGRAM

Commented [A62]: LUMA now proposes to have this Attachment 9 removed from this Regulation and incorporated into the TIR which will facilitate future necessary or suitable revisions or updates to this document while still being subject to Energy Bureau approval.

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