NEPR

Received:

May 19, 2022

6:39 PM

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 Complete Version of Technical Interconnection Requirements Document**

MOTION SUBMITTING COMPLETE VERSION OF TECHNICAL INTERCONNECTION REQUIREMENTS DOCUMENT

TO THE PUERTO RICO ENERGY BUREAU:

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

On July 15, 2021, this Puerto Rico Energy Bureau of the Public Service Regulatory Board ("Energy Bureau") issued a Resolution and Order (the "July 15 Resolution") notifying that it had developed a draft for a new comprehensive interconnection regulation (titled *Generating Facility and Microgrid Interconnection Regulation*) ("Preliminary 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.

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.

After other procedural events, on October 15, 2021, LUMA requested this Energy Bureau to provide LUMA until November 15, 2021, to submit additional and more detailed comments to the Preliminary 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.

On November 15, 2021, LUMA submitted additional comments to the Preliminary Interconnection Regulation Draft. *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"). Among others, and in pertinent part, in the 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 technical document, referred to as "Technical Interconnection Requirements" ("TIR") for review and approval by the Energy Bureau separately from the proposed regulation. *See* November 15th Motion at pages 3-4.

Accordingly, in its November 15th Motion, LUMA submitted, as Exhibit 2 thereof, a preliminary draft of the TIR document ("Preliminary Draft TIR") that would be proposed for separate review and approval by this Energy Bureau. *See id*. LUMA informed that the Preliminary Draft TIR contained the proposed technical requirements for interconnection of Generating Facilities and Microgrids at the distribution level. *See id*. LUMA also explained that additional revisions to the Preliminary Draft TIR were required to incorporate the technical requirements for interconnection at transmission/sub-transmission level, which drafting required additional time. *See id*. Therefore, LUMA requested this Energy Bureau to accept the Preliminary Draft TIR as a demonstration of LUMA's progress in the preparation of a comprehensive TIR document and provide LUMA additional time to complete this document. *See id.*

LUMA has now finished drafting the technical requirements for interconnection at transmission/sub-transmission level and incorporated these requirements in the Preliminary Draft TIR resulting in a comprehensive draft TIR document which LUMA herein submits for this Energy Bureau's consideration as Exhibit 1 hereto ("Proposed Comprehensive TIR"). The Proposed Comprehensive TIR also contains revisions to some provisions of the Preliminary Draft TIR containing the technical requirements for interconnection at the distribution level that were made to further clarify or rectify requirements.

It must be noted that, although the attached Proposed Comprehensive TIR addresses the subject of smart inverters, further elaboration is required to address the complex subject of smart inverter settings in this document. LUMA welcomes input from the Energy Bureau on the subject and would like to respectfully reserve the right to include additional provisions on the subject as more information is obtained from this Energy Bureau and stakeholders.

LUMA respectfully restates its request in the November 15th Motion that the detailed technical requirements for interconnection be removed from the Preliminary Interconnection Regulation Draft (and the final version approved by the Energy Bureau (the "Final Interconnection Regulation")) and that LUMA be allowed to use the Proposed Comprehensive TIR as the TIR for any interconnection governed by the Final Interconnection Regulation. The Proposed Comprehensive TIR would therefore remain a separate technical document from the Final 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. Revisions to the TIR would be approved by the Energy Bureau without triggering a rulemaking proceeding.

LUMA takes this opportunity to inform this Energy Bureau that after going through the rigorous process of drafting the attached Proposed Comprehensive TIR as a complementary document to the Preliminary Interconnection Regulation Draft, LUMA has additional comments to the Preliminary Interconnection Regulation Draft, particularly with respect to the subjects of DG evaluations, supplemental study cost values, and DG interconnection capacity cap per feeder. LUMA plans to submit these comments at the appropriate time- be it within any additional comment period that may be provided by this Energy Bureau with respect to this document, if any, or during the comment period provided by this Energy Bureau when it issues the proposed regulation in a formal rulemaking proceeding. LUMA welcomes the opportunity to be able to do so before the formally proposed regulation is issued to minimize revisions to the proposed regulation. However, LUMA understands that this approach would be at the Energy Bureau's discretion.

WHEREFORE, LUMA respectfully requests this honorable Energy Bureau to **take notice** of the above, accept the Proposed Comprehensive TIR in **Exhibit 1** as the Technical Interconnection Requirements to be applied by LUMA for interconnections governed by the Final Interconnection Regulation, and grant LUMA's request that the Proposed Comprehensive TIR document remain and be approved as a separate technical document from the Final Interconnection Regulation as stated herein.

RESPECTFULLY SUBMITTED.

In San Juan, Puerto Rico, this 19th day of May 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

Comprehensive TIR

LUMAPR.COM

Technical Interconnection Requirements

NEPR-MI-2019-0009

Last Updated: May 19, 2022

Table of Contents

1. 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. 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*

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

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 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.*

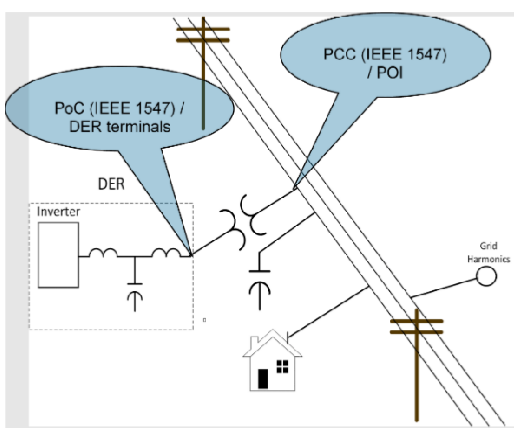
- ***Plant*** *– One or more DERs which are producing electric power.*

- ***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. General Review Requirements

3.1 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.

3.2 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.

3.3 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. 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.

4.1 Inverters

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

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

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.

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 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.

4.1.1 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).

4.2 Synchronous Generators

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

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

4.3 Battery Storage

Evaluation of DER Battery Energy Storage Systems (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.

4.4 Induction Generators

Customers shall be required to install mitigating equipment in cases where Induction Generators for intermittent sources cause voltage or reactive current issues. 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. 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

5.1 Applicable Voltages

The applicable voltages determine the performance of a Local EPS or DER and are the electrical quantities specified about the Reference Point of Applicability, individual phase-to-neutral, phase-to-ground, or phase-to-phase combination and time resolution.

5.1.1 Medium-Voltage Connections

For DER with a PCC located at the medium-voltage level, the applicable voltages shall be determined by the configuration and nominal voltage of the Area EPS at the PCC. 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)

5.1.2 Low-Voltage Connections

For DERs with a PCC located at the low-voltage level, the applicable voltages shall be determined by the configuration of the low-voltage winding of the power transformer(s) between the medium-voltage system and the low-voltage system. The applicable voltages that shall be detected are shown in Table 5-3. 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.

5.2 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.

5.2.1 Distribution Service Transformer Capacity

There are size limits for the transformer relative to the DER. The following size considerations shall apply to determine when a DER Interconnection Application requires a service transformer upgrade:

- If the aggregate DER output is greater than the transformer nameplate rating, it shall be replaced.

$$\sum_b DER_b \geq S_N$$

- If the existing service is open wye-open delta banks and the DER is three-phase. And if single phase DER exceeds 20% of the capacity of the transformer or is expected to create an unbalance in current of more than 20%.
- When voltage-rise associated with DER power back feed is anticipated the service transformer may need to be upgraded to maintain voltage with standard limits.

5.2.2 Replacement Transformer Configuration Requirement

The following winding configuration requirements shall apply where a DER Interconnection Application requires a transformer replacement or an additional transformer:

Acceptable	Grounded Wye / Grounded Wye[1]
	Grounded Wye / Delta[1]
Conditionally Acceptable	Delta / Delta[2]
	Delta / Wye[2]
	Delta / Grounded Wye[2]
	Grounded Wye / Wye[2]

[1] This transformer option may impact the MV protection coordination and require review and potential modifications to settings.

[2] Acceptable with three phase overvoltage protection that coordinates with 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).

5.2.3 Basic Insulation Levels (BIL)

Rating of any new transformer must coordinate with the requirements of the EPS at the PCC. All Customer equipment should be designed to the BIL rating of the EPS line to which it is being Interconnected.

5.3 Effective Grounding

The DER Interconnection (inclusive of DER assets and 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 ≠ 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.

5.4 Cease to Energize

DER cease to energize performance requirements are specified in IEEE Std 1547™-2018 clause

4.5. Cease to energize is identified as "cessation of active power delivery." This still allows for limited Reactive Power from passive devices. This function is specified in several DER response requirements.

5.5 Control Capability Requirements

The DER shall respond to external inputs that include tripping the unit, limiting Active Power, and executing mode or parameter changes. Any control capability will require Telemetry. These capabilities need to be Interoperable to exchange status and readily follow the external input.

Requirements are specified in IEEE Std 1547™-2018 clause 4.6. Limiting DER Active Power is normally to a maximum agreed set point, or in the case of DER combined with load, it may be the net export power including load variations. This normally allows up to 30 seconds of limited, inadvertent export that does not cause operating violations.

5.6 Prioritization of DER Responses

The priority or precedence of different DER response requirements to varying conditions are laid out in IEEE Std 1547™-2018 clause 4.7. These include disabling permit service, trip, Ride Through, voltage-Active Power mode, Active Power limit and voltage regulation modes.

5.7 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.

5.8 Inadvertent Energization of Area EPS

IEEE Std 1547™-2018 clause 4.9 - Inadvertent Energization of the Area EPS requires that the "DER shall not energize the Area EPS when the Area EPS is de-energized."

5.9 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.

5.9.1 Synchronization

Requirements for synchronization are specified in IEEE Std 1547™-2018 clause 4.10.4 - Synchronization. These requirements provide maximum voltage step changes when synchronizing and synchronization parameter limits for different DER kVA.

5.10 DER Interconnection integrity

This Section addresses immunity requirements of the DER to operate properly and safely in typical and expected grid environments. These DER certification requirements intend to promote electromagnetic compatibility of the DER with the Grid and are covered in IEEE Std 1547™- 2018 section 4.11.

5.10.1 Electromagnetic Interference

IEEE Std 1547™-2018 clause 4.11.1 - Protection from Electromagnetic Interference (EMI) identifies the DER immunity requirements for DER performance-critical controls and protections.

5.10.2 Surge Withstand

Voltage and current Surge Withstand requirements for the DER are specified in IEEE Std 1547™-2018 clause 4.11.2 - Surge Withstand Performance.

5.10.3 Paralleling device

Requirements for the Paralleling Device, including the requirement to withstand “220% of the DER rated voltage across the DER Paralleling Device,” is specified in IEEE Std 1547™-2018 clause 4.11.3 - Paralleling Device.

6. DER Support of Grid Voltage

6.1 Reactive Power Capability

All DER installations will be required to have Reactive Power support capability. This means the individual DERs, or the DER systems (at PCC or plant level), shall be capable of injecting Reactive(over-excited) and absorbing Reactive Power (Under Excited). As specified in IEEE Std 1547™-2018, there are category A and B capability requirements as shown in Table 6-1.

Table 6-1. Applicable Minimum Reactive Power injection and absorption capability

Category	Injection capability as % of rated apparent power (kVA)	Absorption capability as % of rated apparent power (kVA)
A (at DER rated voltage)	44	25
B (over the full extent of ANSI C84.1 range A)	44	44

For both categories A and B, the full kVAR minimum capability is required for Active Power output levels above 20% of rated power. For reduced real power output levels, from 5% to 20%, the DER % Reactive Power requirement is calculated by % Active Power/20% rated Active Power.

6.2 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.

6.3 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.

6.4 Active Power Control

The DER may be required to provide voltage regulation capability by changes of Active Power. Modes of voltage regulation using Active Power control include Volt/Watt and Active Power-Reactive Power mode.

Active Power control requirements are specified in IEEE Std 1547™-2018 clause 5.4 - Voltage and Active Power Control. The standard identifies required voltage-Active Power control function requirements and setting requirements for Category B generation. Table 10 in this clause identifies Voltage-Active Power settings. EPS Operator will provide the proper settings.

7. DER Response to Abnormal Conditions

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

7.1 Area EPS Faults

DER protective devices shall be rated to safely interrupt fault current levels at the location. Available fault current levels depend on the Point of Connection. The requirement will include the aggregate fault current expected from all sources, the range of fault current scenarios and for all expected feeder operating alternatives.

Requirements for area EPS faults including cease to energize and trip requirements is specified in IEEE Std 1547™-2018 clause 6.2.1 -Area EPS Faults.

7.2 Open-Phase Conditions

Requirements for open-phase include cease to energize and trip within 2 seconds of an open-phase condition and are specified in IEEE Std 1547™-2018 clause 6.2.2. The DER facility must be able to sense open-phase conditions at the Reference Point of Applicability (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.

7.3 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.

7.4 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.

7.5 Frequency trip and Ride Through requirements

Frequency Trip settings and Ride Through capability requirements for Abnormal Conditions are specified in IEEE Std 1547™-2018, clause 6.5, and are the same for Category I, II, and III. 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. 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.

8.1 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.

8.2 Unintended Islanding Detection

Anti-islanding capabilities are required for all DERs and for all installations. The anti-islanding protection shall trip the DER within 2 seconds of the formation of an island (loss of Grid power). Trip time for DERs on feeders protected with automatic reclosers will need to be coordinated with the reclosing systems. This may require additional equipment such as transfer trip or suitable alternative.

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.

8.3 Transfer Trip Protection

Often referred to as Direct Transfer Trip (DTT), this protection is used for most Synchronous Generators and for larger inverter connected DER installations. It may be required for smaller DER applications when the feeder hosting capacity exceeds Buffer Zone limits by DER connections. The objective of DTT is to quickly and reliably remove feeder distributed generation when Grid power is interrupted. A secondary objective for DTT is to clearly distinguish events where the DER should not trip.

In most cases a fiber-optic cable or another acceptable communications medium is required to coordinate with the protection scheme of the Distribution System. This requirement depends on DER type, unintended island detection and/or DER penetration levels relative to the feeder capacity. Criteria currently being applied where transfer trip is required include:

- Any inverter-connected systems greater than 750 kW or where the installed DER capacity has or is anticipated to exceed the safety Buffer where reverse power on any 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.

8.4 Overcurrent Protection

The DER shall not generate current flow more than the component rating for EPS equipment. This is inclusive of allowable, emergency, and fault duty system ratings.

Overcurrent protection and ground fault overcurrent protection is required to be coordinated with upstream protection devices and should be set to be capable of sensing faults on the Interconnected feeder.

For synchronous generators, a directional overcurrent element may be required.

8.5 Short Circuit Current Interrupting Capacity

When adding DERs, the short circuit current levels (in aggregate from all sources) resulting from the addition of the DER shall not exceed 85% of the interrupting rating of any impacted EPS or Customer-owned protective devices and equipment.

The DER (in aggregate from all sources) shall not contribute more than 10% of the Distribution System's maximum available fault current at the primary voltage Point of Common Coupling (PCC). If this limit is exceeded additional engineering review may be required.

The DER Customer may be required to redesign their facility to reduce fault contributions. These redesigns include, but are not limited to:

- Installing a generator with adequately large sub transient reactance
- Installing a transformer with sufficiently high impedance
- Installing a current-limiting reactor

8.6 Protective Relays (or built-in protection functions)

Interconnection configurations are site and feeder dependent. 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.

8.6.1 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.

8.7 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.

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.

8.8 Remote Trip (via Cellular or Radio) Capability

An Automatic Circuit Recloser (ACR) may be required at the Customer's expense for systems 1 MW and greater. This is not an alternative to any DTT protection requirements.

The ACR shall have appropriate relaying and remote-control capability. Depending on location and coordination with other feeder protection, the ACR monitors local voltage and plant current and may be programmed to trip for generator or feeder faults, for sustained voltage outside of predefined limits, and for outages.

NOTE: If the DER is behind the Customer's Meter, EPS Operator will work with the Customer to establish a means of tripping the DER without loss of service to other loads.

8.9 Other Equipment and Protection Requirements

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

9.1 Limits on DER DC Injection

Direct current, or a DC-offset, from DERs is restricted because low-levels can saturate instrumentation and Interconnection transformers causing mis-operation of protective devices that can lead to power outage. Limits during normal operation are specified in IEEE Std 1547™- 2018 clause 7.1 - Limitation of DC Injection.

9.2 Limits on DER-caused Voltage Fluctuations

Voltage fluctuation limits depend on both the DER relative size and the strength of the Grid (Stiffness Ratio) at the PCC. The main concerns are DER-caused fluctuations on the medium voltage power system. 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.

9.2.1 Rapid Voltage Change Limits

In normal operation the DER shall not cause RVC changes that exceed ΔV of 3% at medium voltage and 5% if the PCC is at low voltage. Excluded are rare events such as transformer energization during a plant start-up or restoration.

9.2.2 Flicker Limits

In normal operation the DER shall not cause repetitive changes of power output leading to voltage fluctuations. To determine compliance, an allocation of the grid’s flicker capacity at the PCC is provided to the DER. The allocation is $P_{st} \leq .35$, based on a 10-minute evaluation of DER-caused 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).

9.2.3 Compatibility with Voltage Regulation Equipment

The DER shall not cause excessive operation of EPS owned voltage regulators, tap changers, and voltage or VAR-switched capacitors. Rapid changes, where the voltage recovers in less than 10 seconds, are excluded. The following change limits shall apply to minimize excessive voltage regulating equipment operations:

- Voltage Regulators – voltage changes are limited to ½ the bandwidth of any voltage regulator (line or substation) measured at the regulating device.
- Capacitors – voltage changes are limited to ½ the net dead bandwidth of any switched capacitor bank measured at the device.
- VAR Switched Capacitors – Reactive Power changes not to exceed ½ the bandwidth of any VAR switched capacitor bank measured at the device.

9.3 Limits on Harmonic Distortion from DER

The DER shall not introduce or promote unacceptable distortions in the Grid voltage sine wave at the PCC. This limit is applied to DER current Total Rated-Current ("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.

9.4 Limits on Transient Overvoltage from DER

DERs Operating in Parallel with the Grid shall not, by their design or application, cause transient overvoltage that may exceed EPS or Customer equipment tolerances. Events leading to overvoltage include interaction of the DER during ground faults, with Grid switching transients, or from disconnection of the DER.

Specific limits are defined in IEEE Std 1547™-2018 clause 7.4 - Limitation of Overvoltage Contribution. If DER cause objectionable overvoltage, then mitigation is required at the DER Owner's/Customer's expense.

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

9.5 Maintaining Phase-Voltage Balance

All 3-phase DER installations shall maintain a balanced power output during normal operations. DER Interconnections may not create current unbalance that causes any phase voltage in service to other users to violate 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:

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

There are three definitions of voltage unbalance. The first definition (IEEE 112), used in the equation above, is using phase measurements. The second definition (NEMA) uses line voltage. The third definition, often times called “true” definition, is defined as V2/V1, 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.

9.6 Grid Integration for Radial-Connected DER

9.6.1 General Requirements

Integration requirements for radial connected DERs address compatibility of the DER plant at the PCC and along the feeder, both above and downstream of the PCC. Requirements depend on the DER, the location, existing condition, and capacities of the feeder. Key concerns are maintaining service voltage within limits for all Customers, operating within the ratings of power delivery equipment, managing reverse power, addressing contingencies requiring feeder reconfigurations and protection coordination. In this Section, limits to the individual and aggregate DER, as well as criteria for feeder upgrades are addressed.

9.7 Aggregate and Individual DER Capacity Limits

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.

9.8 Substation Power Transformers Limits

The aggregate of large DER will be limited to 50% of the substation transformer normal rating. In the case of transformers paralleled on the low side, the limit is 50% of the sum of the transformer normal ratings. This usually ensures that the LTC does not operate excessively. Note that small systems (less than the large system size for the circuits' voltage class), may continue to be interconnected when these distribution transformer limits are reached.

The absolute net reverse power limit is 40% of the transformer normal rating. This ensures that locations with transfer capability can operate safely where one transformer load automatically transfers to the remaining transformer upon outage of one transformer. Note that OLTCs can get damaged if regulating voltage when power is flowing in reverse. For this reason, if 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.

9.9 Thermal Operating Limits

An Interconnection shall not thermally overload any electrical equipment based on manufacturer ratings and industry practices for determining limits. Thermal limits shall be based on system rating during normal operation. This includes loading capacity of conductors as determined by size, conductor material, and duct configuration. In addition, the design must ensure that circuit losses on the distribution feeder are equal or less that 3% demand loss and 3% annual energy loss.

Curtailment systems may be used to mitigate overloads and are an accepted practice to assure that thermal limits are not exceeded.

9.10 DER Customers with Multiple Radial Services

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.

9.11 Reconfiguration of Radial Circuits

Circuit reconfigurations of a feeder are not allowed to accommodate an Interconnection. Circuit reconfiguration may occur for accommodating load and should be beneficial to the EPS– improving voltage, loading, transfer capability, etc.

For a new high-side breaker position, the construction and/or modification of the existing bus will be required. The new position shall not utilize a planned future transmission line, distribution transformer, mobile unit, or planned capacitor position.

9.11.1 Distribution Automation ("DA") Schemes

Experience has shown that DA schemes can be compromised by large DER systems in concentrated areas. Both fault location and switching can become more difficult.

The DER shall not interfere with Distribution Automation (DA) schemes. Where DERs may interfere with existing DA schemes (e.g., FLISR- fault location, isolation, and service restoration), the following design requirements shall apply:

- DERs applying within Distribution Automation zones shall not interfere with the proper operation of the scheme. The range of load and DER output levels are checked to ensure proper operation under all conditions otherwise mitigation is required at Customer expense.
- DERs proposed within existing protection and automation schemes must be integrated and interoperable to maintain existing levels of reliability.
- Systems 250 kW and greater, applying to circuits that have or can have DA schemes, will be required to have telemetry. This will provide monitoring of electrical parameters and in the future, control capability that can be exercised during reconfiguration.

9.11.2 **Load Transfers**

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

9.11.3 **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.

9.11.4 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.

9.11.5 Reverse Power Safety Buffer Requirements

In addition to the requirements discussed above, minimum size of the operating Buffer for equipment at its rated voltage shall be in accordance with the following table.

Table 9-2. Minimum size of Buffer 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.

9.12 Feeder Upgrade Options and Requirements

9.12.1 Service Transformer/Secondary Conductor Upgrades

The following analysis and design requirements shall apply where an Interconnection less than 50 kW requires an upgrade to the service transformer and/or secondary conductors. A voltage rise analysis should be performed for any project to determine if the transformer, secondary conductors, or service wire should be upgraded. If available, AMI voltage data will be used to support the voltage rise analysis. If an upgrade is required, the least-cost upgrade correcting the issues should be selected.
For larger primary connected, 3 phase systems, the following transformer requirement may apply:

- Any DER greater than or equal to 250 kVA may require load taps (+/- 2.5 and 5% typically).
- For DERs in areas where a voltage level is being retired, the 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.

9.12.2 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.

9.12.3 Feeder Voltage Regulators

Where a DER Interconnection requires a voltage regulator to be added or upgraded, this must be completed before approval to operate. 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.

9.12.4 Capacitor Banks

The following requirements shall apply where a DER Interconnection requires a capacitor bank upgrade or a relocation on the circuit:

- Fixed capacitor banks may be upgraded to switched type, removed and/or installed at a new location, as appropriate.
- EPS Operator will determine settings for switched capacitor banks in coordination with any DER Reactive Power response settings, during Interconnection technical review.

9.13 Circuit & Bus Reconfigurations

Circuit reconfigurations are not allowed to accommodate an Interconnection. From time to time, 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. Plant Interoperability

10.1 General Requirements

Requirements for Interoperability of the DER is specified in IEEE Std 1547™-2018 clause 10 Interoperability, Information Exchange, Information Models, and Protocols. DERs are expected to follow these requirements. This chapter defines additional and/or more specific requirements for EPS Operator and clarifies which systems must be connected to telecommunications networks for data to be collected and/or exchanged.

10.2 Interoperability for DER Plants

Interoperable Telemetry shall be available in all DERs following IEEE Std 1547™-2018 clause 10. These requirements include more extensive monitoring, control, and information exchange requirements covering many parameters including nameplate information, configuration information, monitoring information, and management information. 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.

10.2.1 Capability Requirements

Interoperability capabilities include specific protocol and communication performance requirements.

IEEE Std 1547™-2018 specifies standardized communications interface for all DERs that shall be locally available at the DER location. Communications should not depend on vendor specific protocol or remote communication. Any setting changes must be reviewed/approved or initiated by 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.

10.2.2 Communication Protocol Requirements

Interoperability requirements include specific protocol requirements and communication performance requirements. IEEE Std. 1547™-2018 specifies three applicable protocols: IEEE 2030.5 (SEP2), IEEE 1815 (DNP3), or SunSpec Modbus. 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.

10.2.3 Unlock Mechanism Requirement

Some DERs have historically included methods to lockout communication through the local interface, usually with passcode access required. Some vendors may continue this practice even after open standards are required. This proprietary step to unlock the device is only allowed for the initial set up and for certification. The open standard protocols do not support this and cannot unlock a DER that has been locked using proprietary means.

For all inverters certified to IEEE 1547-2018, 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.

10.3 DER Communication Interface

10.3.1 DER Plant Requirements

The plant shall provide all Telemetry, control, and associated equipment that is required to meet the Telemetry requirements highlighted throughout this document. This equipment includes DER Interoperability requirements as well as Interoperability with the plant controller. This equipment shall meet EPS Operator specifications.

10.3.2 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.

10.4 Monitoring, Control, and Information Exchange

10.4.1 Inverter-connected Generation Requirements for DER greater than or equal to 1 MW

Any inverter-based generation project that is 1 MW or larger shall be required to install communications to ensure real-time SCADA Telemetry.

Any project 1 MW to 5 MW requires:

- Installation of a recloser or acceptable approved device. All SCADA points listed below – except relay failure status
- Polling Rate of 5-minute intervals or shorter as required by 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

10.4.2 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. 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. Commissioning and Verification Requirements

12.1 General Requirements

This section covers several steps to verification that the Interconnection meets requirements and can be commissioned. It covers a commissioning process including configuration of DER functional setting, evaluation of documentation, determination of tests required to be completed before Witness Testing. References to determine test requirements that depend on the plant size and type, as well as any specific protective relay test requirements are provided. This section also covers recommissioning and periodic testing.

Specific requirements for each project will be communicated to the Customer/ DER Owner /Developer. These requirements will be a subset of the items found in this section.

12.2 DER Commissioning Process

The DER facility commissioning process shall be planned and carried out by the Customer after construction is completed and the site is ready to be energized. At a minimum, the scope of the commissioning process to be performed shall include commissioning tests specified by IEEE Std 1547™-2018, clause 11.2.4.3 - DER as-built installation evaluation, clause 11.2.5 - Commissioning tests and verifications, and clause 11.3 - Full and partial conformance testing and verification. The commissioning process shall verify that the facility does not create adverse system impacts to the electric Grid and to other Customers served by the grid.

12.3 Configuration of Functional Settings

Prior to commissioning tests, the IC shall configure the DER facility's functional settings by means of one of the following options:

- Option A: Selection of a manufacturer-automated profile (MAP)
- Option B: Use of a configuration and validation toolkit that uses the local DER communication interface
- Option C: Integration with the EPS's DER settings requirements or if applicable, the EPS DER management system (DERMS)

12.4 Evaluation of Documentation

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

12.4.1 Review to Confirm As-Builts

The following installed equipment information is required in a final as-built plan before Witness Testing for confirmation of consistency with previously provided documentation:

Equipment	Information Required
Inverter	- Ratings: Mfg., Model, Rated kW, V on the application will be compared to equipment installed in the field. - Inverter Firmware Version - Inverter Settings
Interconnection transformer[1]	Load side winding connection, High side winding connection, Primary Voltage, Secondary voltage, Rating, and % impedance if Customer owned. If owned by the EPS, a contractor supplied picture of the transformer with its size and ID number clearly visible will be used to verify information in GIS. This can speed up secondary voltage rise analysis and service transformer adequacy where data may not be complete in GIS.
Primary fuse / recloser[1]	Rating / Settings
Primary PTs for Ground Fault Protection[1]	The EPS primary PT's shall be wired to 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.

12.5 Commissioning Tests

12.5.1 Protective Relay Tests

Qualified testing personnel must perform tests on the IC's Protective Relaying prior to energizing from the EPS. Testing requirements will be evaluated and determined on a case-by-case basis by 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.

12.5.2 Plant Commissioning Tests

Commissioning requirements are dependent on the size of the DER, DER certification, and whether the RPA is PCC or PoC as identified in IEEE Std 1547™-2018. The following criteria will be considered to identify the commissioning test requirements of the IC.

- Certification of DER for RPA at PoC or DER System for RPA at PCC. Classifications include DER Unit (PoC), DER 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

12.5.3 Required Witness Tests

Before Parallel Operation with the EPS, and after completion of commissioning tests, additional Witness Testing may be required and inspected by EPS Operator. The IC is responsible for providing qualified personnel who will complete all required tests. Witness Testing is generally required for larger 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.

12.6 Recommissioning

Recommissioning is required, under certain circumstances, after the original commissioning and Witness Testing is completed. The extent of recommissioning is dependent on the reason for the commissioning and the effect on the DER Interconnection. Partial recommissioning may be required as part of the regular testing of basic functionalities of protective and control functions. These tests are expected and may need to occur in time frames typically ranging from every year to every 10 years depending on manufacturers recommendations and 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.

12.7 Periodic O&M and Testing

12.7.1 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.

12.7.2 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. 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. 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.

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.

14.1 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.

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.

14.3 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]

14.4 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

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

as needed under multiple system configurations scenarios.

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.

14.5 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.

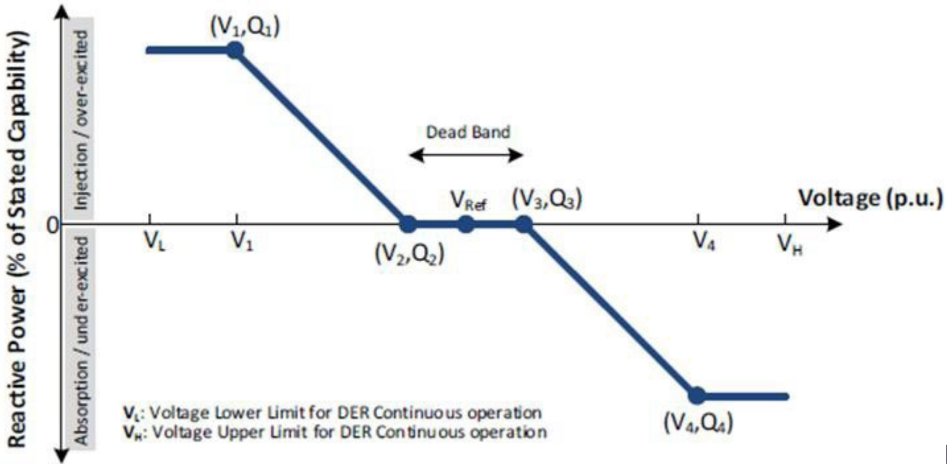


Figure 14-1. Example voltage-reactive power characteristic

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.

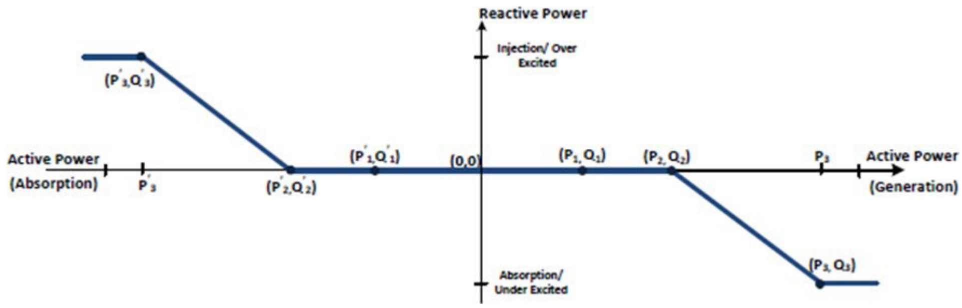


Figure 14-2. Example Active Power-Reactive Power characteristic

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.

14.6 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.

14.7 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

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.

14.8.1 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.

14.8.2 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.

14.9 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.

14.10 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).

14.11 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

14.12.1 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	

14.12.2 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).

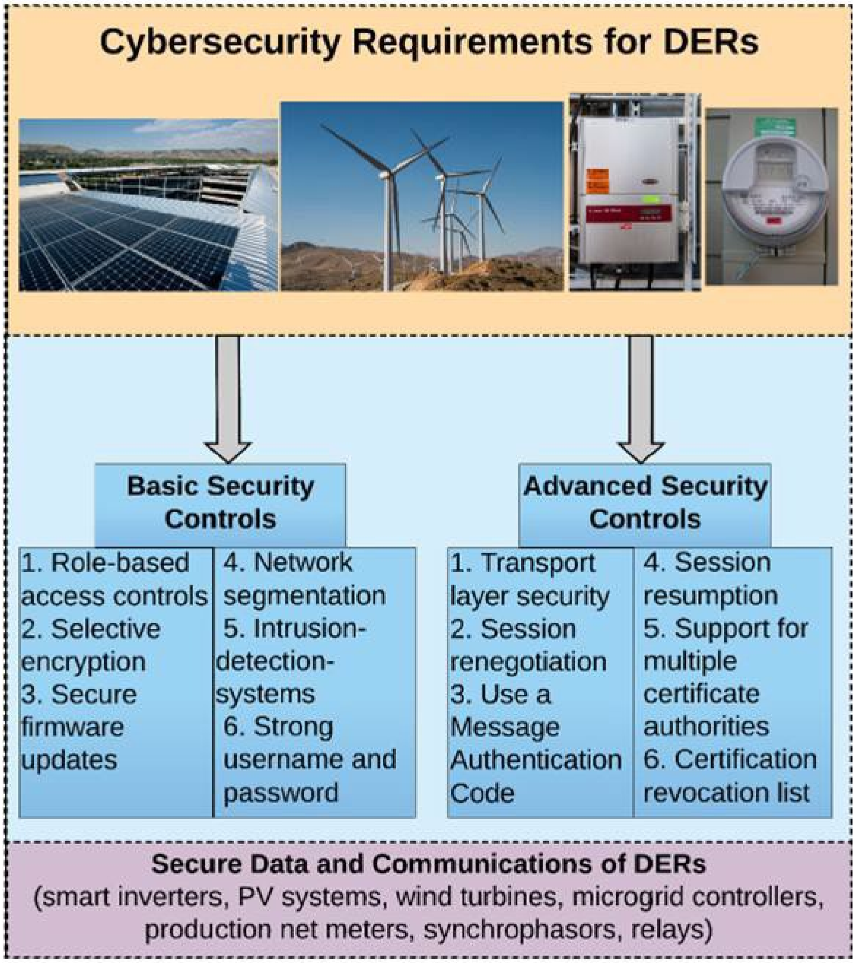


Figure 14-3. High-level overview of cybersecurity requirements for DERs and Microgrid[5]

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.

14.13 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.

14.14 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 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.

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.

14.14.1 **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).

14.14.1.1 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.

14.14.1.2 *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.

14.14.1.3 *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

14.14.2 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

14.14.3 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.

14.14.4 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. Transmission and Sub-Transmission Interconnections

15.1 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).

15.2 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.

15.2.1 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.

15.2.2 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.

15.2.3 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.

15.2.4 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.

15.2.5 Power Quality

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

15.2.6 Transient Mathematical Model

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

15.2.7 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.

15.3 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.

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

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

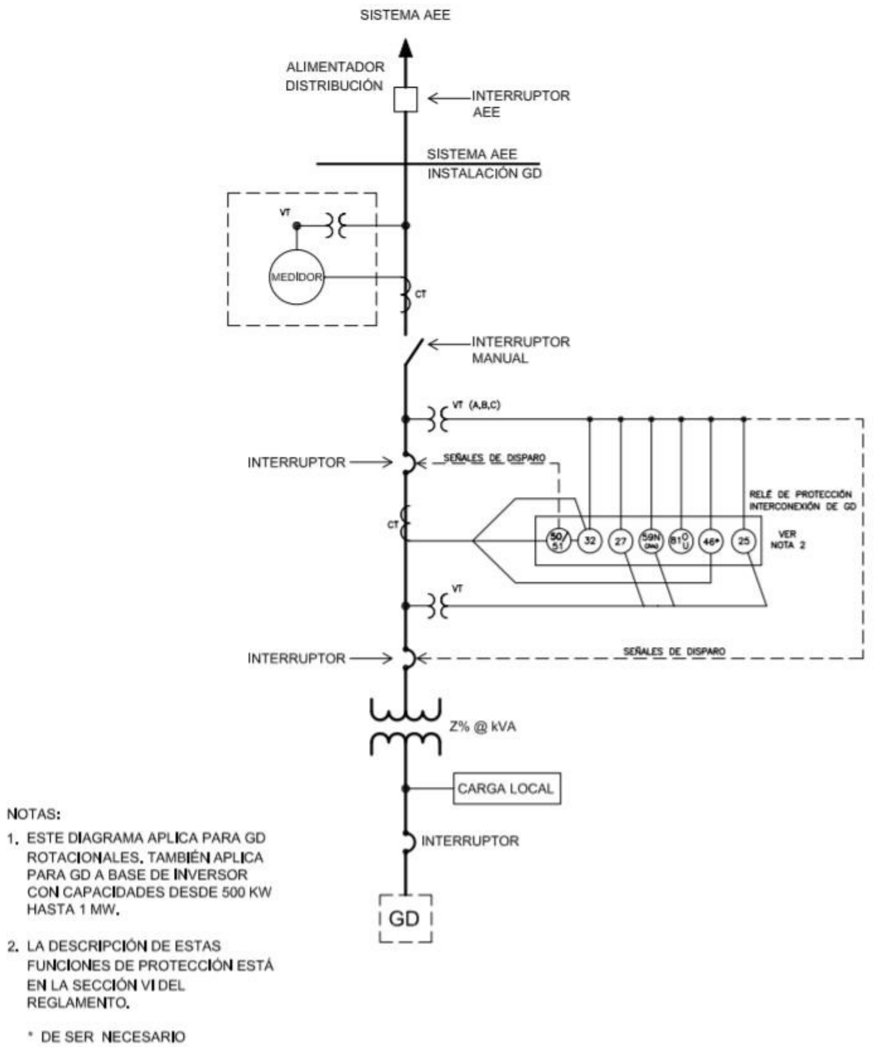
Common DER Configurations			*These are general guidelines for protection requirements and may vary based on IC's total system configuration. Individual protective device functions may be implemented using multifunction relay.+*					
Config 1a	**Config 2a, 2b, 3a, 3b, 4a, 4b**	**Config 1b**	**Config 2d, 3d, 4d**	**Config 1c, 2e, 2f**	**Config 2b, 2d, 3b, 3d, 4b, 4d**	**Config 2c, 2d, 3c, 3d, 4c, 4d**	**Config 1c, 2e, 2f**	**Config 2a, 2b, 2c, 2d, 3a, 3b, 3c, 3d, 4a, 4b, 4c, 4d, 5a, 5b, 5c**
11 - Multifunction Device/Relay - Required protective functions may be implemented in a single multifunction relay								
	✓		✓	✓	✓	✓	✓	✓
21 - Distance or Impedance - Requirement determined by capacity. Does not apply to inverter-based generation								
			✓ Other directional protection may be utilized in lieu.		✓	✓ Other directional protection may be utilized in lieu.	✓	✓
25 - Synchronizing or Synchronism Check (Customer DER location) – May only be required for rotating equipment								
		✓	✓	✓	✓	✓	✓	✓
25 - Synchronizing or Synchronism Check/Backfeed Detection (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.								
	✓		✓		✓	✓	✓	✓

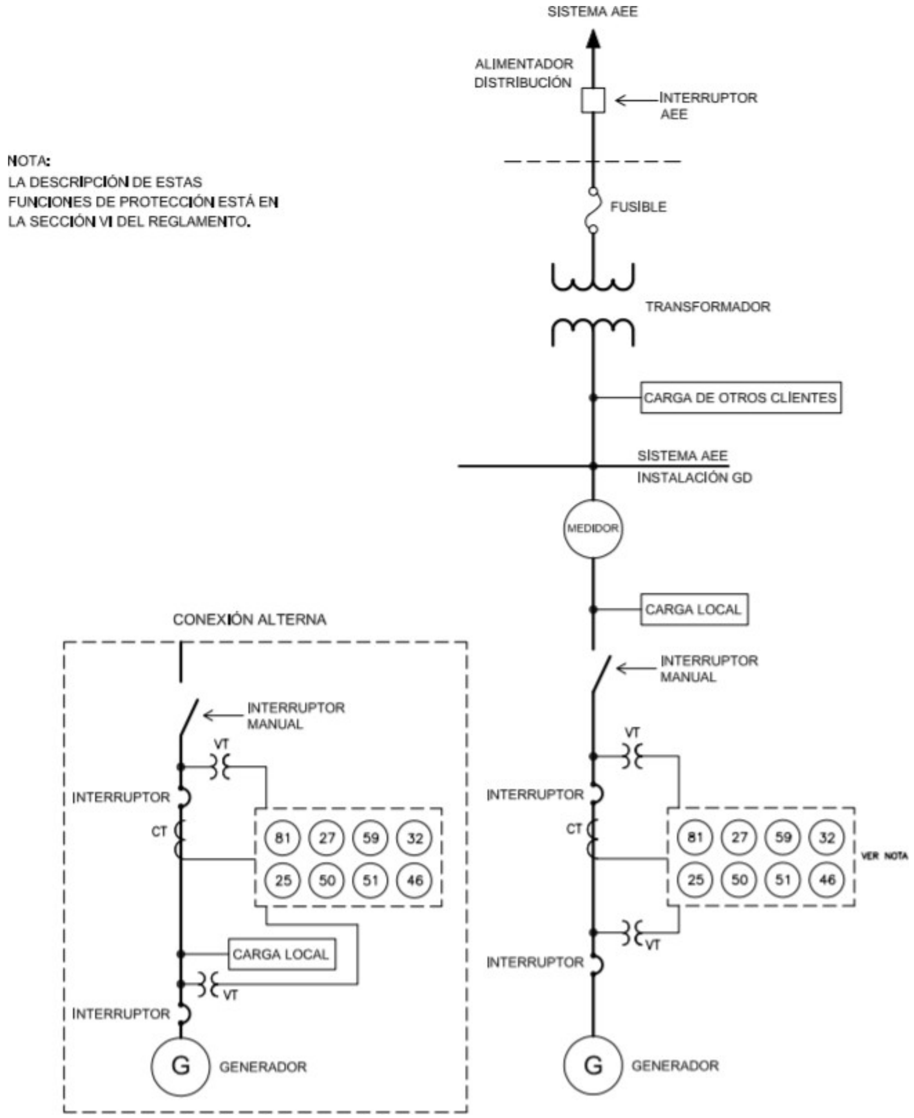
Appendix D: Typical One-Line Diagrams

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.

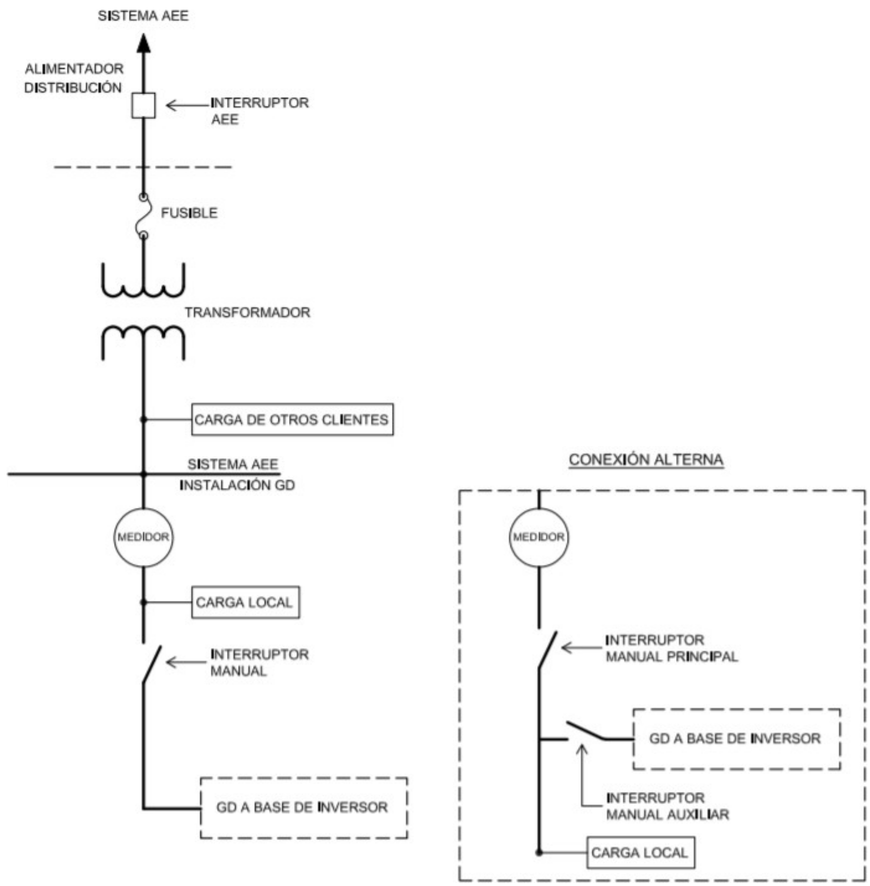
1.1. Diagram 1 – Synchronous Generator Connected to the Primary Distribution Network



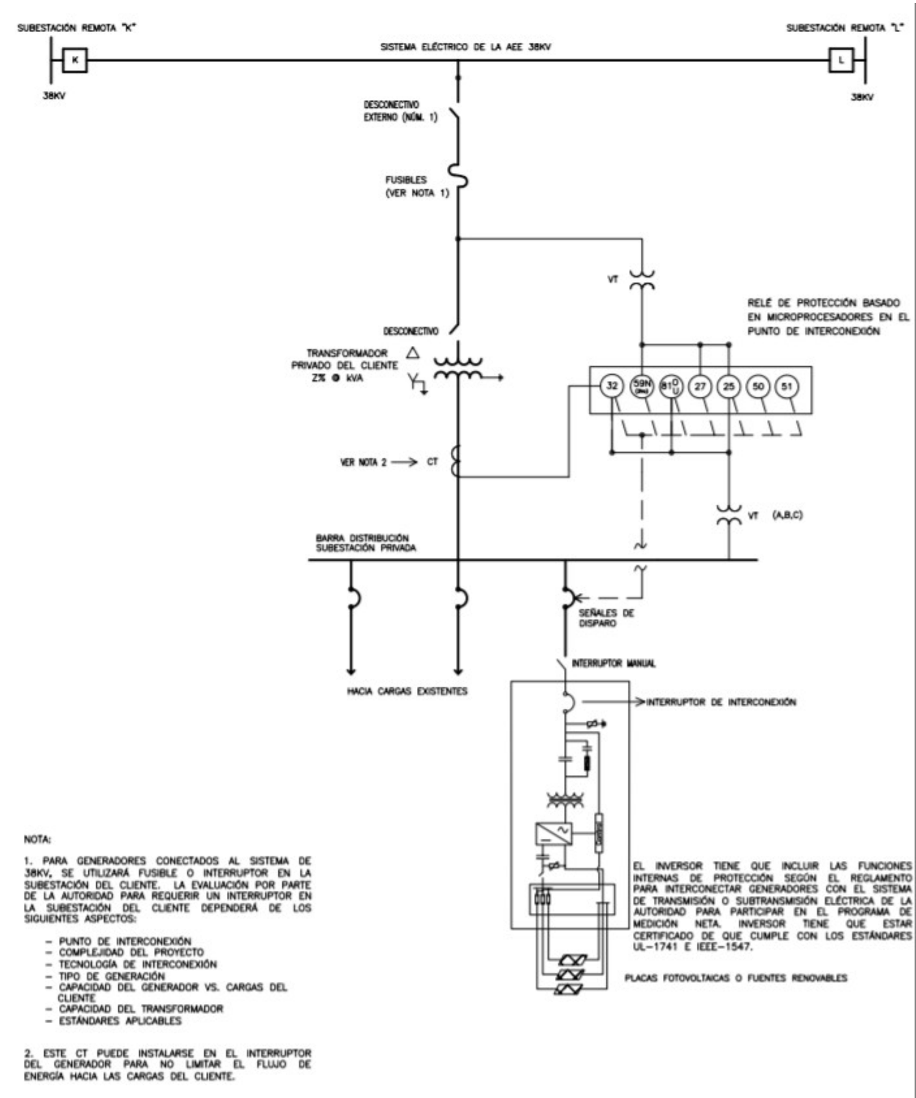
1.2. Diagram 2 – Synchronous Generator Connected to the Secondary Distribution Network



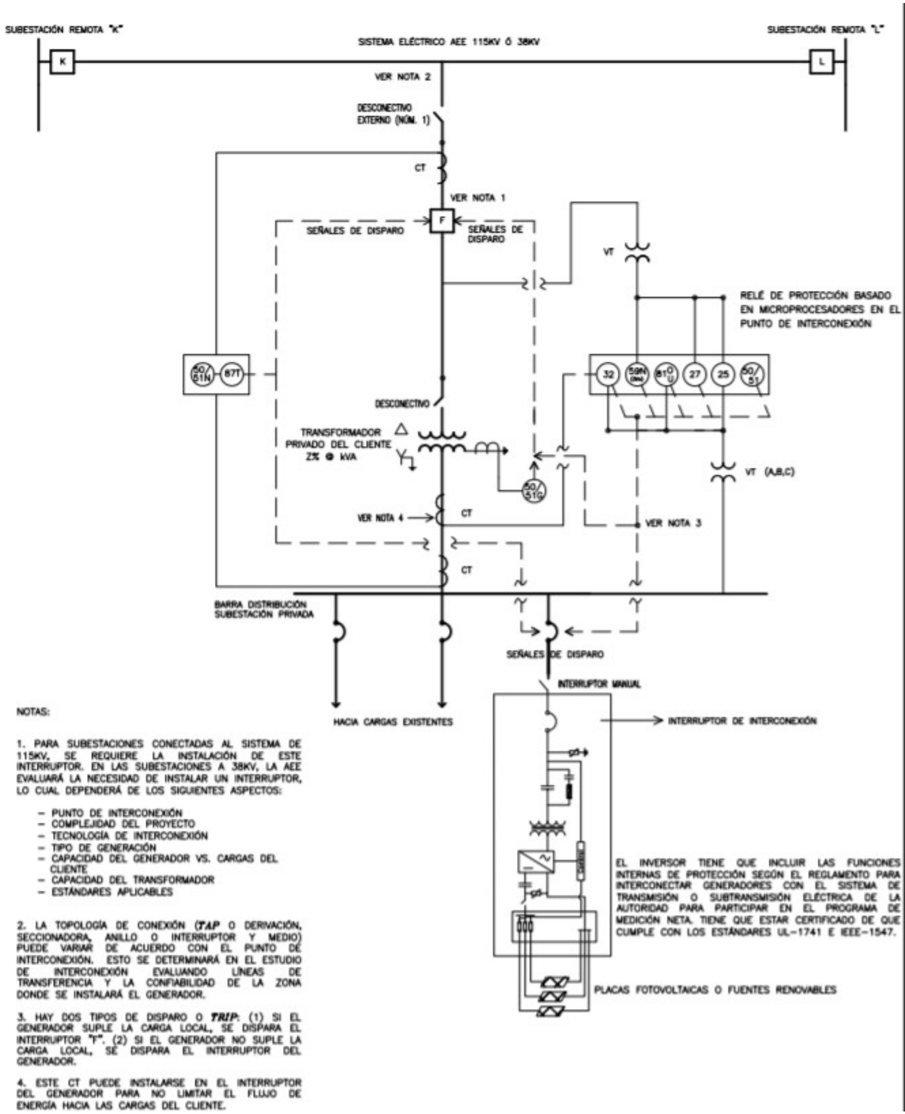
1.3. Diagram 3 – Connection of inverter-based DER to the Secondary Distribution Network



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



NOTAS:

1. PARA SUBESTACIONES CONECTADAS AL SISTEMA DE 115KV, SE REQUIERE LA INSTALACIÓN DE ESTE INTERRUPTOR. EN LAS SUBESTACIONES A 38KV, LA AEE EVALUARÁ LA NECESIDAD DE INSTALAR UN INTERRUPTOR, LO CUAL DEPENDERÁ DE LOS SIGUIENTES ASPECTOS:

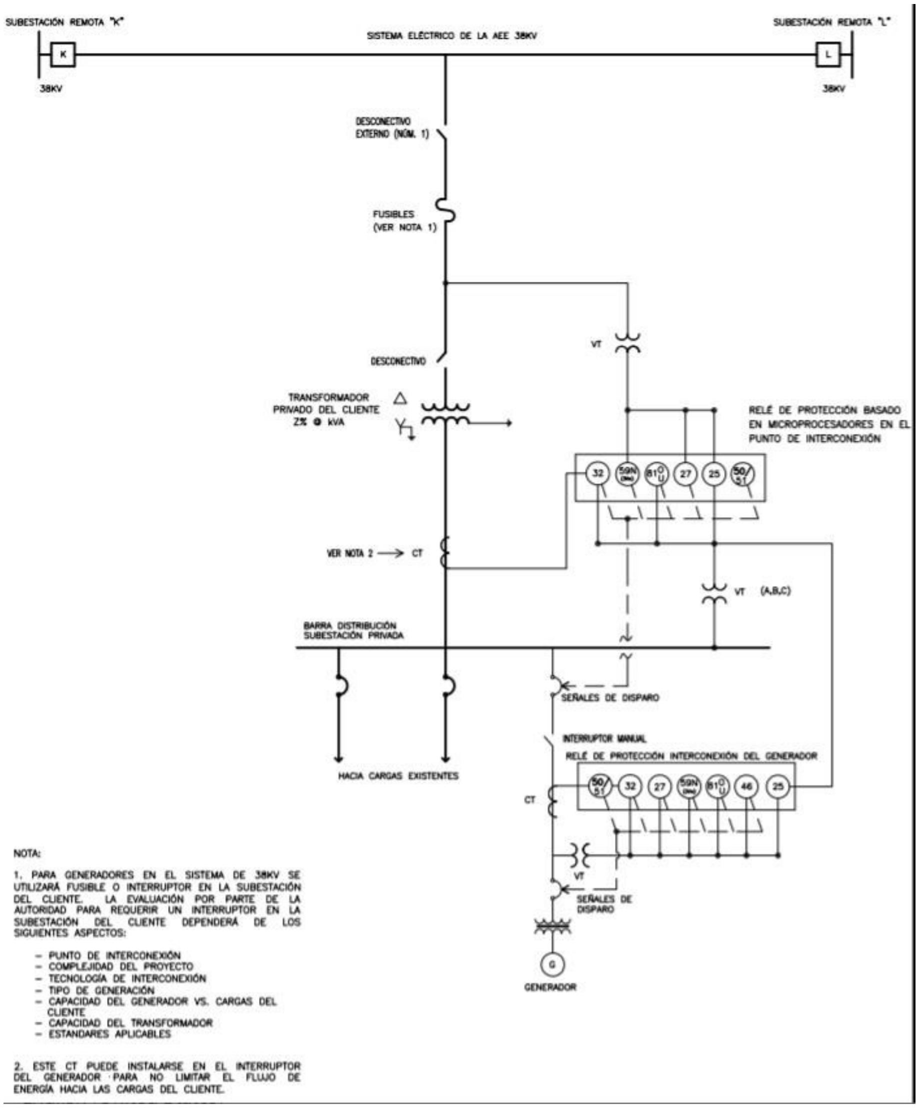
   - PUNTO DE INTERCONEXIÓN
   - COMPLEJIDAD DEL PROYECTO
   - TECNOLOGÍA DE INTERCONEXIÓN
   - TIPO DE GENERACIÓN
   - CAPACIDAD DEL GENERADOR VS. CARGAS DEL CLIENTE
   - CAPACIDAD DEL TRANSFORMADOR
   - ESTÁNDARES APLICABLES

2. LA TOPOLOGÍA DE CONEXIÓN (***TAP*** O DERIVACIÓN, SECCIONADORA, ANILLO O INTERRUPTOR Y MEDIO) PUEDE VARIAR DE ACUERDO CON EL PUNTO DE INTERCONEXIÓN. ESTO SE DETERMINARÁ EN EL ESTUDIO DE INTERCONEXIÓN EVALUANDO LÍNEAS DE TRANSFERENCIA Y LA CONFIABILIDAD DE LA ZONA DONDE SE INSTALARÁ EL GENERADOR.

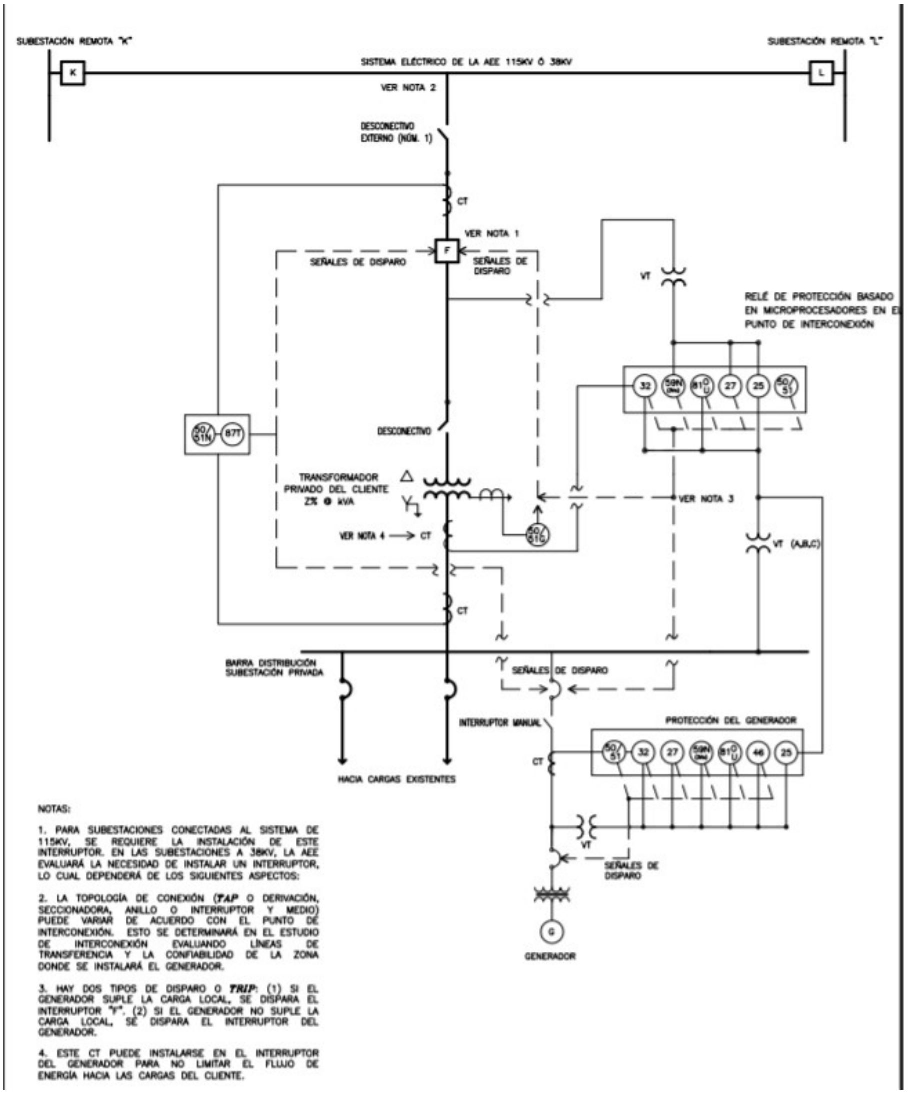
3. HAY DOS TIPOS DE DISPARO O ***TRIP***: (1) SI EL GENERADOR SUPLE LA CARGA LOCAL, SE DISPARA EL INTERRUPTOR "F". (2) SI EL GENERADOR NO SUPLE LA CARGA LOCAL, SE DISPARA EL INTERRUPTOR DEL GENERADOR.

4. ESTE CT PUEDE INSTALARSE EN EL INTERRUPTOR DEL GENERADOR PARA NO LIMITAR EL FLUJO DE ENERGÍA HACIA LAS CARGAS DEL CLIENTE.

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

1.9. Interconnection Feeder Protection

The protection applied to a line terminal at the Generating Facility's site that Interconnects the privately-owned Generating Facility with the EPS will vary depending on the voltage class and existing line relaying scheme at the EPS end(s). Typical protection schemes for various voltage Interconnection lines are provided below. The actual schemes used will vary for each specific site.

Typical Line Terminal Protection Schemes Line Voltage Class	Line Protection Schemes
38kV and below	· Phase & Ground Over current (may need to be directional) · 3-Phase to Ground Connected Under Voltage & Over Voltage (For line terminating in delta or ungrounded wye connected transformer)

100kV and above	· Line protection schemes will follow the 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

- Generating Facilities selling into the EPS Grid marketplace that have their under-Frequency trip point set to meet EPS under frequency operational requirements (such as 57.5 Hz. for 5 Seconds) essentially removes under frequency sensing as a sensitive means to detect isolation. In this case, other protective measures, such as transfer trip, will be required.
- In cases where a transfer trip scheme is needed to ensure isolation detection, the failure of the transfer trip scheme or communication channel will require that the Generating Facility automatically disconnect from the EPS until the transfer trip scheme is restored.
- If a Generating Facility back feeds a substation distribution transformer with an ungrounded high side winding, a transfer trip scheme will be required. Any installation over 750 kW will require DTT.
- Transfer trip schemes shall only utilize a fiber path as a communication medium.

1.11. DER Generator Protection Schemes

- The protection schemes on Generating Facilities will become more complex as the size of the Generating Facility unit increases. Multi-function microprocessor relays can be used to provide several generator 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

Appendix F: Commissioning Checklist

Steps		Subject	Notes	Completed? Yes	No	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

<table>
<tr><th>Type</th><th>Benefits</th><th>Risk</th><th>Costs</th><th>Timing</th></tr>
<tr><td rowspan="3">Fiber - EPS Operator installed</td><td>- Ensure scope, cost, and schedule</td><td>- Higher costs</td><td rowspan="3">- Included in Study estimates</td><td rowspan="3">Per EPS Operator construction schedule</td></tr>
<tr><td>- Highly reliable x5 - 9's</td><td>- Required to run fiber to substation</td></tr>
<tr><td></td><td>- Single spur is less reliable</td></tr>
</table>