Distributed Energy Resource Technical Interconnection Requirements

ENMAX Power Corporation

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Distributed Energy Resource

Technical Interconnection Requirements

A MESSAGE TO THE DISTRIBUTED ENERGY RESOURCE PROVIDER

This document is intended for a technical audience. The requirements established throughout this document are intended to provide guidance to the Distributed Energy Resource (DER) Provider on the interconnection of a DER Facility with the ENMAX Power Corporation Distribution System (EPC Distribution System). These interconnection requirements include, but are not limited to the following:

1. Preliminary planning;
2. Project execution;
3. Procurement;
4. Construction;
5. Testing and commissioning;
6. Energization; and
7. Operation and maintenance.

The information and requirements contained in these EPC DER Technical Interconnection Requirements (Technical Requirements)[1] are not a substitution for the EPC formal interconnection process. All process documentation and relevant interconnection information can be found on enmax.com.

For all interconnection inquiries, please contact EPC's Customer Intake Department at DERConnect@enmax.com.

REVISION HISTORY

DATE	VERSION	COMMENTS
February 15, 2019	Rev. 0	New Document
November 15, 2022	Rev. 1	Update to align with CSA C22.3 NO.9-20 and IEEE 1547-18
December 15, 2022	Rev. 2	Additional information included on ride-through requirements
December 15, 2025	Rev. 3	Updates and additional requirements including further aligning with IEEE 1547-2018, Alberta IEEE 1547-2018, AESO Primary Frequency Response Guideline, Common File Format for DER Settings, further of application of DER settings, and guidance on further interconnection requirements

REVISION OVERVIEW

The 2025 update to the EPC DER Technical Interconnection Requirements includes changes to the operation of DER to align with the industry changes to DER interconnection requirements around grid support including primary frequency response. This aligns with further interoperability requirements that state how DER shall respond to certain system disturbances and fluctuations. Additionally, this update includes further guidance on DER provider responsibilities, isolation devices, enter service requirements including ramp rates, reactive power capabilities and functions required, effective grounding reporting, additional study and reporting requirements including commissioning reporting, aggregations of DER, electric vehicle power export, testing standard requirements for energy storage facilities, and the common file format for exchange of DER settings with ENMAX Power.

[1] The Technical Requirements is subject to change, and EPC reserves the right to change its policies, procedures and standards when deemed necessary.

Key updates in this document are written in Blue for ease of identification.

Rev No.	Effective Date	Major Revisions History	Responsible	Authenticated
1	**December 15, 2025**	Section 1: Update of key applicable industry standards, signage, and DER Provider responsibilities. Section 3: Additional guidance on isolation devices required, Frequency Droop requirement added, enter service and ramp rate requirements incorporated, effective grounding requirements detailed, further study requirements for export into EPC substations, electric vehicle export, EMT studies and guidance on theory of operation reporting. Section 4: Further guidance on Open phase protection and Direct Transfer Trip, requirements for DER aggregators incorporated Section 6: Requirement for provisions of read and write DER settings information exchange. Section 8: Updated ENMAX metering standard link Section 11: UL1741 SB reference updated, testing standard requirements for energy storage systems added, further guidance on design evaluation and preparing commissioning testing plans including IEEE Conformity Assessment Program (ICAP) requirements, and providing DER settings using the EPRI Common File Format for DER Exchange Appendices: Appendix 5 and 6 on Common File Format for DER Exchange added. Appendix 7 on typical volt-var and volt-watt requirements included.	Juval Bothe	PROFESSIONAL ENGINEER JUVAL V. C. BOTHE ALBERTA 2025-12-16 ID# 83486
2	**December 16, 2022**	Section 3: Detail added on voltage and frequency ride-through requirements.	Juval Bothe	Name: Juval V.C. Bothe ID: 83486 Date:2022-11-20
		Section 4: Detail added on minimum frequency and voltage tripping requirements.	Manveer Aujla	Name: Manveer Aujla ID: 95922 Date: 2022-11-30
1	**December 5, 2022**	Sections 1, 2, 3, 5, 8, 9, 10, 11: General updates and updates to align with CSA C22.3 NO.9-20 and IEEE 1547-18	Juval Bothe	Name: Juval V.C. Bothe ID: 83486 Date:2022-11-20
		Section 4: General updates and updates to align with CSA C22.3 NO.9-20 and IEEE 1547-18. Added detail on Ride-Through requirements.	Manveer Aujla	Name: Manveer Aujla ID: 95922 Date: 2022-11-30

		Sections 6 & 7: General updates and updates to align with CSA C22.3 NO.9-20 and IEEE 1547-18	Amir Esmaeil	Name: Amir Esmaeil Kaboli ID: 234252 Date: 2022-11-30

ENMAX POWER – Permit to Practice

PERMIT TO PRACTICE
ENMAX POWER CORPORATION

RM SIGNATURE:

RM APEGA ID #: 77937

DATE: December 16 2025

PERMIT NUMBER: P006756

The Association of Professional Engineers and Geoscientists of Alberta (APEGA)

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1.0 INTRODUCTION

ENMAX Power Corporation (EPC) owns, operates, and maintains the electricity transmission and distribution system in and around the City of Calgary.

The EPC Distribution System is constantly changing due to several factors that include the interconnection of new technology, population density change resulting in load growth/ change, and governing requirements. These changes shift the overall electrical system parameters. The addition of Distributed Energy Resources (DER) will prompt significant changes regarding how the system is operated and maintained. With the evolution of technology, both EPC and the electric power industry anticipate continued technological and operational changes to distribution systems over time to continue to integrate DER in a way that enables a greener, affordable grid. The North American Electric Reliability Corporation (NERC) considers a DER to be the following:

> *… any resource on the distribution system that produces electricity and is not otherwise included in the formal NERC definition of the Bulk Electric System (BES).*[2]

DERs include all sources of electrical energy including synchronous, asynchronous, and solar/inverter-based generation, as well as energy storage solutions. More specifically for the purposes of the Technical Requirements, a DER is defined[3] as:

> *A source of electric power that is not directly connected to a bulk electric system, which includes distributed connected generation and energy storage technologies.*

DER resources have the capability of delivering their produced or stored power onto the local distribution or transmission systems and can have an impact on public safety, system reliability, power quality, and system response.

The Technical Requirements are intended for use by a DER Provider who is considering the development of a DER Facility that will be interconnected with the EPC Distribution System.

DER Facility and DER Provider are defined as:

> *DER Facility* - All equipment including DERs, interconnection systems, transformers, protection and coordination systems, sensing devices on the DER Provider's side of the point of common coupling*; and*
>
> *DER Provider* - A Person who owns, operates or is otherwise responsible for a DER Facility that is interconnected to the EPC Distribution System for the purpose of generating electric power.

The requirements outlined in these Technical Requirements are designed to support safe operation and minimize the impact to electrical equipment on the EPC Distribution System. The responsibilities outlined for both EPC and the DER Provider are required to minimize impacts to EPC, the DER Provider and other Customers.

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[2] NERC Distributed Energy Resources Task Force Report, February 2017

[3] All definitions used in the Technical Requirements are included for reference in Appendix 1.

The Technical Requirements have been developed to inform and familiarize all Customers, DER Providers (owners and operators), developers, designers, engineers, manufacturers, contractors, and other interested parties with the requirements associated with the interconnection of a DER Facility with the EPC Distribution System. The Technical Requirements describe the design, operation, performance, safety, reliability, protection, testing and maintenance of an interconnected DER Facility.

A DER or DER Facility failing to meet the interconnection requirements set out in the Technical Requirements to EPC's satisfaction will not be connected to the EPC Distribution System. A DER or DER Facility is required to continue to meet the Technical Requirements, or it can be subject to disconnection.

1.1 OBJECTIVES

EPC provides services for the interconnection of DER Facilities with the EPC Distribution System that maintain the safety, power quality, reliability and operational requirements of the EPC Distribution System for all its Customers. These services are provided in compliance with applicable provincial and federal laws and regulations including international design standards.

The Technical Requirements were developed in accordance with the following objectives and are required to be followed throughout the lifecycle of a DER Facility.

1. **SAFETY** – DER Facility interconnections must maintain safety for the public, Customers, EPC employees, or anyone who works on the EPC Distribution System, and personnel working in the DER Facility;
2. **POWER QUALITY** – DER Facility interconnections must maintain the EPC Distribution System power quality at the acceptable levels outlined within the Technical Requirements;
3. **RELIABILITY** – DER Facility interconnections must not diminish the reliability of the EPC Distribution System as mandated by the Alberta Utilities Commission (AUC), Alberta Electric System Operator (AESO) and EPC;
4. **OPERATION** – DER Facility interconnections must maintain the operational abilities of the EPC Distribution System; and
5. **STANDARDS -** DER Facility interconnections must meet EPC's Standards.

1.2 PURPOSE AND LIMITATIONS

The requirements outlined in the Technical Requirements apply to any individual or aggregated DER Facility interconnected with the EPC Distribution System at voltages ≤ 25kV phase-to-phase.

Any exemptions to these requirements must receive written approval from EPC prior to interconnection. The criteria and requirements in the Technical Requirements are applicable to all DER technologies and to the primary and secondary voltages of the EPC Distribution System. DER Facility interconnections with radial primary and secondary distribution systems are the main emphasis of the Technical Requirements, although secondary network and high-density distribution systems are also included.

The Technical Requirements were developed with reference to the requirements of the Canadian Standards Association Group (CSA), Institute of Electrical and Electronics Engineers (IEEE), Alberta Utilities Commission (AUC), Canadian Electrical Code (CEC), Alberta Electrical Utility Code (AEUC), and Association of Professional Engineers and Geoscientists of Alberta (APEGA). More specifically, the

Technical Requirements require compliance standards and codes[4] including the following, which may be updated and amended from time-to-time:

- *IEEE Std 1547-2018 IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces*.
- *IEEE Std 1547.1-2020 IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems*
- *CAN/CSA C22.3 No. 9-20 Interconnection of Distributed Resources and Electricity Supply Systems*;
- *Alberta Electrical Utility Code (as applicable); and*
- *CSA C22.1-24 Canadian Electrical Code Part I, Safety Standard for Electrical Installations*.

The Technical Requirements specify the minimum requirements for the interconnection of a DER Facility with the EPC Distribution System. Depending on the circumstance, additional requirements may be applicable to the DER Provider to ensure that the final interconnection design meets all applicable EPC, municipal, provincial, national, and international standards and codes, and that the design is safe for the application intended.

The Technical Requirements do not address any liability provisions agreed to elsewhere by the DER Provider and EPC, or the EPC Distribution Tariff - Terms and Conditions (EPC Ts&Cs).

Specific types of interconnection schemes, DER technologies, and the EPC Distribution System may have additional requirements, standards, recommended practices, including other required documentation external to the Technical Requirements. EPC will engage the DER Provider to address these issues as required during the DER interconnection process.

The Technical Requirements are not a design manual nor is it a substitute for responsible engineering practice. All requirements listed within the Technical Requirements are minimum requirements. A DER Provider intending to interconnect to the EPC Distribution System is advised to hire a qualified professional engineer licensed by APEGA and comply with APEGA's *Authenticating Professional Work Products* standard. It is essential that these technical resources have related engineering experience in Alberta to ensure compliance with all provincial codes, standards, and all other requirements directed by EPC. Given the complexity of an application, ENMAX reserves the right to request professionally stamped documentation for projects.

1.2.1 MOMENTARY CLOSED TRANSITION (NON PARALLEL) EXCLUSIONS

The Technical Requirements are intended primarily for DER(s) Facilities intending to export power onto EPC's Distribution System. A DER Facility with DER(s) operating in parallel with the EPC Distribution System for 6 cycles or less (Momentary Closed Transition), including open transition, only needs to follow the requirements described in Subsection 4.2.

[4] A summary of codes and standards referenced in the Technical Requirements are included in Appendix 4.

1.2.2 Signage

This document follows the following sign conventions when describing flow of active and reactive power to/from ENMAX Power's distribution system with the following respective terms: export/import for active power and inject/absorb for reactive to help maintain clarity.

1.3 RESPONSIBILITIES

1.3.1 EPC Responsibilities

EPC is responsible for the following:

1. Operating the EPC Distribution System within all governing laws, regulations, codes and standards, including licensing and the requirements of:
   - AESO;
   - AUC;
   - AEUC; and
   - All other applicable Canadian/international requirements and standards;
2. Providing safe, reliable, and quality power delivery while ensuring that the DER Facility interconnection does not negatively affect the EPC Distribution System or Customers;
3. Developing, updating, and enforcing the Technical Requirements; and
4. Notifying impacted Customers of any relevant system changes and updated requirements in a timely manner.
5. EPC will be responsible for the design, construction, maintenance and operation of the Facilities on EPC's side of the Interconnection Demarcation Point. This responsibility excludes the communication link on the DER Provider side of the telecommunication Demarcation Point (Telecommunications Demarcation Point). Refer to Section 7.0 for more information on the Telecommunication Demarcation Point.

1.3.2 DER PROVIDER Responsibilities

The DER Provider is responsible for the following:

1. Safely designing, constructing, operating, and conducting proper maintenance of the DER Facility;
2. Designing and operating the DER Facility in compliance with all applicable codes and standards, including licensing and the requirements of:
   - AESO
   - AUC
   - AEUC
   - IEEE 1547-2018, IEEE 1547.1-2020
   - Alberta 1547-2018
   - All other applicable Canadian/international requirements and standards;
   - As required, compliance can include curtailment of a DER's electrical production to align with applicable codes, regulations, standards, the customer's interconnection agreement, or this document.
3. Operating the DER Facility only within the terms and conditions of the Operating Procedures;
4. Acquiring all required permits and licenses, such as municipal permits, approvals, and inspections (e.g., City of Calgary, Municipal District of Rocky View, AUC, AESO, etc.);

5. Ensuring the DER Facility is compliant with these Technical Requirements and any other interconnection-related documents issued by EPC. If the DER Facility is determined to be non-compliant or is found to be negatively affecting the EPC Distribution System or Customers, the DER Provider must suspend operation of the DER Facility until compliance can be proven with supporting documentation provided to EPC;
6. Ensuring that DER facilities that consist of one or more DER units, maintain reliable aggregate performance of the entire DER facility at the RPA even in the event of loss of communications or failure of individual DER units to perform.
7. Ensuring DER Facility is compliant with AESO requirements as required including when aggregate installed DER are at least 5 MW or larger or smaller as required by AESO.
8. Making all necessary changes to the DER Facility and providing all supporting documents to EPC within 60 days of receiving written notification from EPC when changes such as configurations, protection and control schemes occur to the EPC Distribution System or in response to:
    - Safety concern;
    - System configuration changes;
    - New or revised standards;
    - New or revised codes; or
    - Legislation changes;
9. Except as otherwise required in Subsection 1.2, and as required by EPC on a case-by-case basis, ensuring that a qualified professional engineer licensed by APEGA reviews and stamps the DER Facility design and protection scheme(s). EPC needs to review and accept all design and protection scheme(s) as part of the application process before to DER commissioning is to proceed;
10. Obtaining EPC's prior written approval for all DER Facility changes, including interconnection equipment replacements, design modifications, and setting changes. Any changes made without the prior written approval of EPC shall be deemed a violation of the EPC Ts&Cs and may result in immediate disconnection from the EPC Distribution System;
9. Installing, owning and operating adequate generator protection as well as protection for other equipment within the DER Facility. These protection schemes prevent damage from faults or abnormal conditions, which may originate at the DER Facility or from the EPC Transmission and/or Distribution Systems;
10. Protecting DER Facility equipment in such a manner that outages, restoration, short circuits, or other disturbances on the EPC Distribution System, do not damage that equipment. DER Facility protective equipment must also prevent excessive or unnecessary tripping that would affect the EPC Distribution System reliability and power quality of other Customers as described in the Technical Requirements;
11. All required changes and associated costs related to the interconnection of the DER Facility with the EPC Distribution System, regardless of where the change was initiated (e.g., EPC, AUC, AESO, Western Electricity Coordinating Council (WECC), NERC, or Federal Energy Regulatory Commission (FERC)). More specifically, the DER Provider is responsible for all interconnection costs, including but not limited to:
    - Studies;
    - Intelligent Electronic Device (IED);
    - Telecommunications infrastructures;
    - All rental fees (as applicable);
    - All project management and engineering required for implementation;
    - Commissioning and testing;

- Ongoing maintenance and DER Facility upgrades; and
- Equipment settings and modifications; and

12. While responsible for all interconnection costs, the DER Provider will not own the protective devices within any EPC-owned Facilities. All other infrastructure, excluding EPC-owned equipment (e.g., telecommunication interface), will be owned and maintained by the DER Provider. Additional EPC equipment may be required to be installed in the DER Facility, as determined by EPC on a case-by-case basis. The DER provider must provide the necessary space for EPC owned interconnection equipment on the facility side of the interconnection demarcation point.

13. The interconnection Demarcation Point may vary depending on both the type of the EPC Distribution System configuration where the DER Facility is to be interconnection and the services types (e.g., primary/secondary service, overhead line/underground cable, etc.), that will be determined during the DER interconnection process.

14. For participation in any AESO products or services including transmission ancilliary services, engagement of AESO as well as EPC is required. Notification to EPC is required for any AESO services or products that a DER facility has been accepted to participate in. Participation in such services may result in changes to any aspects of a DER facility's interconnection including DER facility design, operational requirements, existing interconnection approvals, interconnection studies required, and interconnection equipment requirements.

1.4 INTERCONNECTION REQUIREMENTS

1.4.1 Interconnection Process

To avoid delays in the interconnection process, the DER Provider must provide complete and accurate information to EPC in a timely fashion at the start of the DER interconnection process. Any changes and/or incomplete information provided to EPC can result in significant delays to the estimated timelines.

The Technical Requirements include references to the requirements for DER interconnection, however, do not address all the site-specific protection and technical aspects of the DER Provider's facility and equipment. It is the responsibility of the DER Provider to ensure that requirements such as scoping, procurement, protection, installation, commissioning, operation and the maintenance of the DER Facility is complete and verified by all appropriate authorities.

Where required, an Interconnection Agreement[5] between EPC and the DER Provider must be signed prior to the energization of the DER Facility.

[5] An Interconnection Agreement containing the Operating Procedures is required to be signed by the DER Provider who is intending to interconnect with the EPC Distribution System.

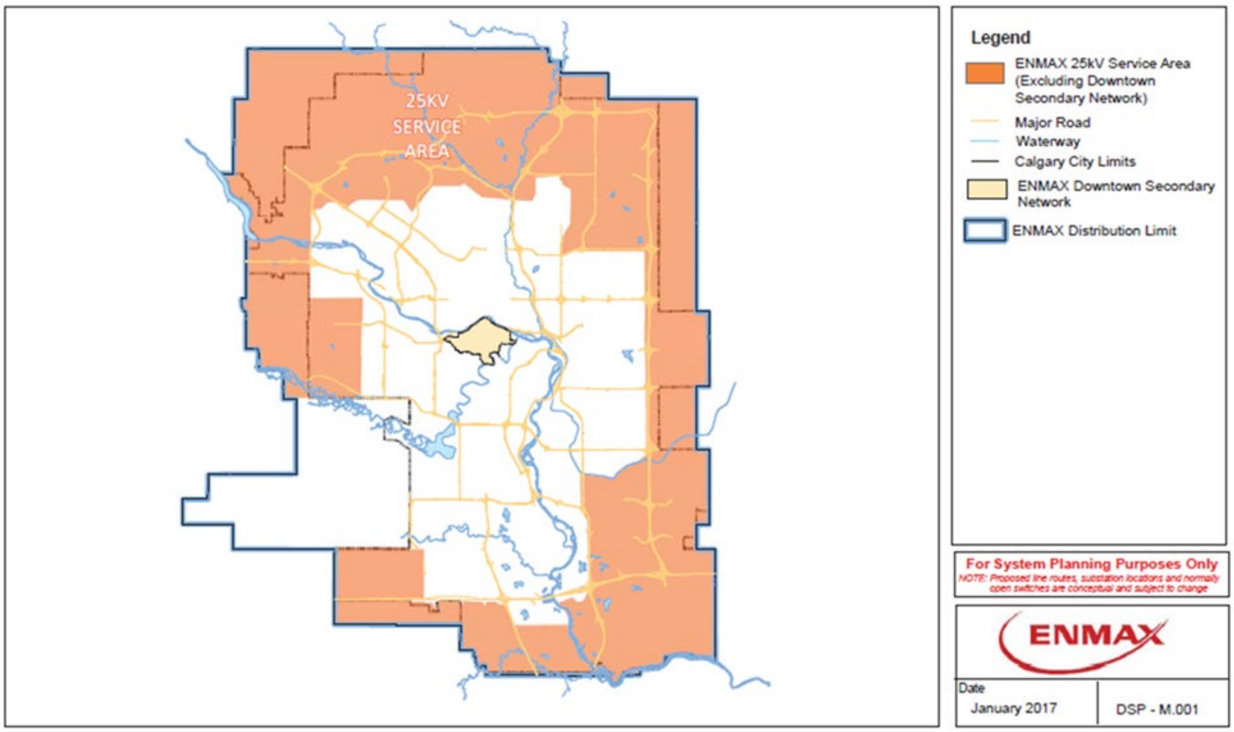
2.0 EPC DISTRIBUTION SYSTEM

This section provides details and constraints of the EPC Distribution System and an overview of system-specific planning and operational criteria.

2.1 DISTRIBUTION SYSTEM CONFIGURATIONS

EPC has two main distribution system configurations: The Radial Distribution System and the Secondary Network System. Figure 1 illustrates the EPC Distribution System configurations.

Figure 1: EPC Distribution System Configurations



2.1.1 Radial Distribution System (Radial System)

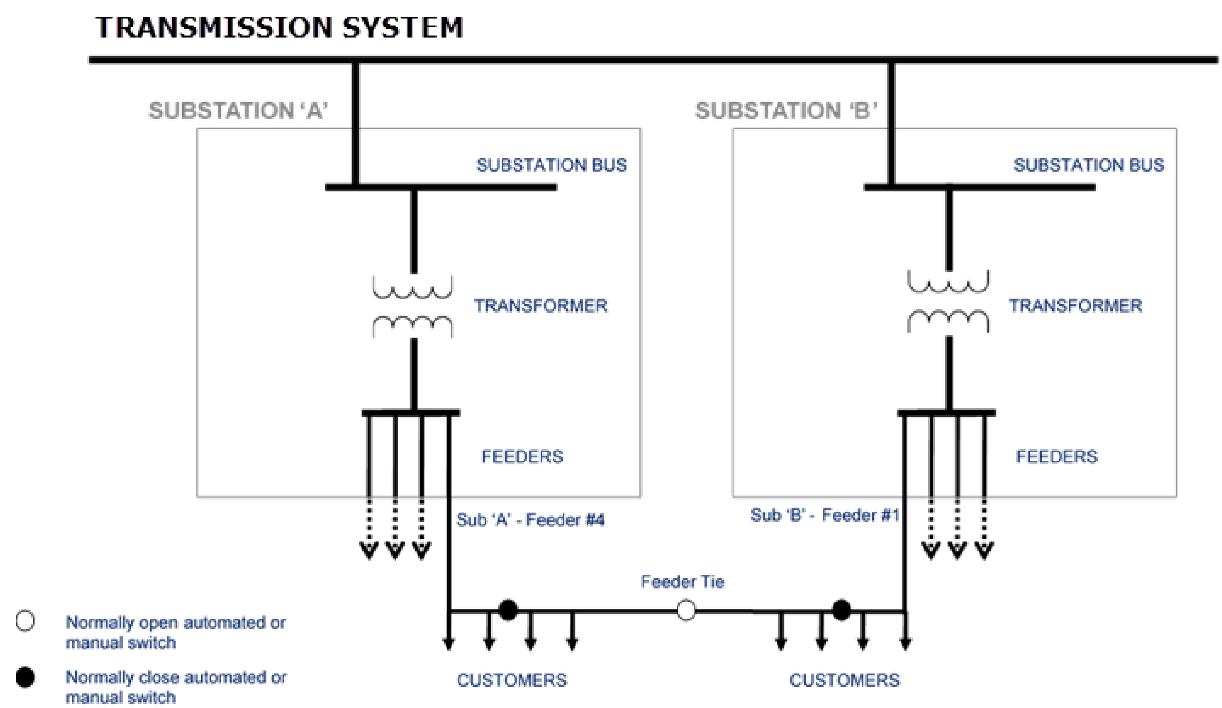
The Radial System supplies most of EPC's service territory including a small number of Customers in the City of Calgary's downtown core. This system provides Customers with services at both primary and secondary voltages. The Radial System has two primary voltage classes: 13kV and 25kV. Please note, this excludes the downtown 25kV servicing system, contact EPC for more information regarding the possibility of connecting DER's to the 25kV Downtown Servicing system.

The 13kV system supplies most of the inner city. The 25kV system supplies the suburban developments beyond the 13kV supply boundaries as well as several buildings located in downtown Calgary.

> The Radial System uses an open-looped design, in which multiple normally-open switching points or feeder ties, provide alternative power supply paths upon the loss of the original primary voltage source. This system also utilizes an extensive matrix of distribution-automated switches. Several automated switches, both in-line switches and tie switches, work together to maintain electrical service to Customers through operational schemes including feeder sectionalizing and restoration. In addition, the automated switches can also function as re-

closers. Stand-alone re-closer devices are also installed on long radial feeder sections. This switching equipment is coordinated with protection and restoration schemes that can impact DER Facility interconnection requirements. Figure 2 illustrates the EPC radial distribution System.

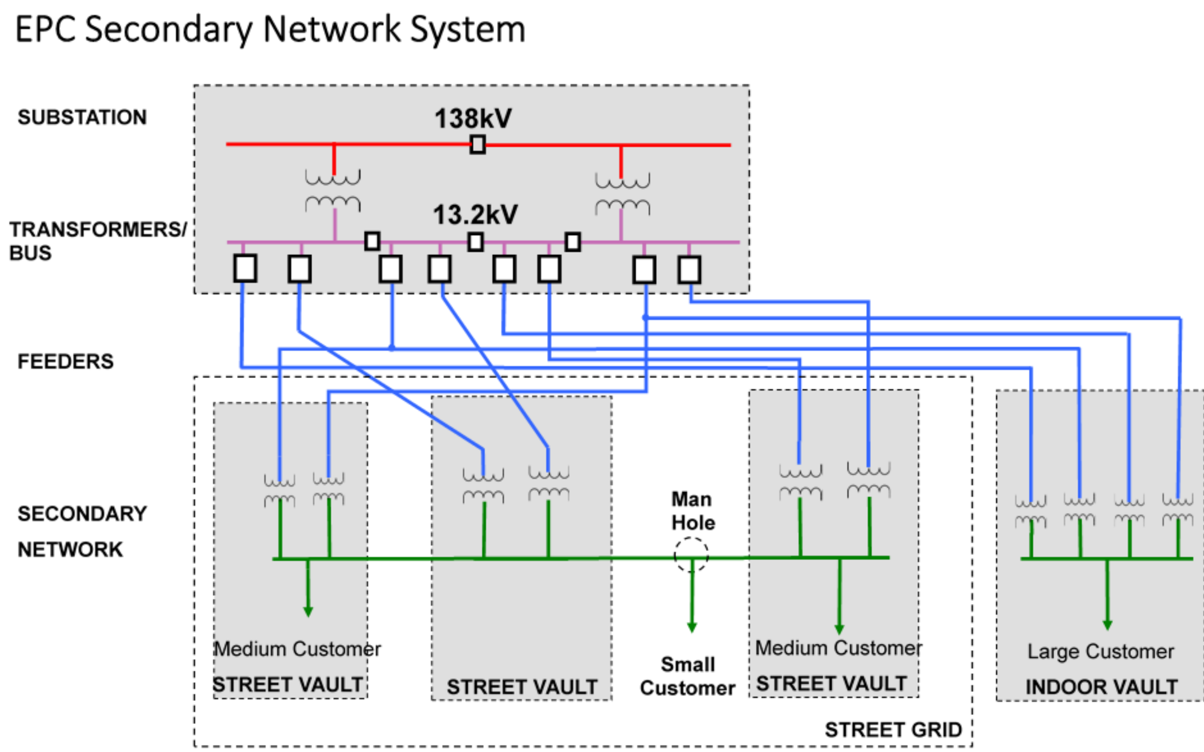
Figure 2: Illustration of EPC Radial Distribution System



2.1.2 Secondary Network System (Network System)

The Network System currently serves most of Calgary's downtown core and a select number of locations outside of the core with service voltages of 120/208V, 277/480V or 347/600V. In these areas, the Network System is designed as secondary voltage mesh-networks (either 'street grid' mesh-network, spot-network, or high density), supplied by multiple 13kV or 25kV feeders. Secondary network equipment is also used to service high-density development areas in other parts of the city where no Facilities can be installed above ground due to municipal zoning approvals that allow no set back building construction. Secondary networks require a unique protection scheme that includes specialized equipment known as network protectors. Network protectors detect and prevent power flow from a secondary network to a primary feeder. Due to the nature of the protection devices, these networks can impose special restrictions on DER interconnections to the Network and high-density Systems. Figure 3 illustrates the Network System.

Figure 3: Downtown Secondary Network System high-level single-line example



2.2 SERVICE VOLTAGE & VOLTAGE REGULATION

EPC maintains the service entrance voltage at all Customer sites in accordance with the criteria of CSA Standard *CAN3-C235-83 (R2015) Preferred Voltage Levels for AC systems 0 to 50 000V*. For secondary services, the voltage range under "Normal Operating Conditions" is outlined in Table 3 of this standard (included in the Technical Requirements as Table 1) and is used by EPC for system planning under normal system operation. A +/- 6% variation from nominal voltage is acceptable for primary service[6].

To maintain service voltage to each Customer within the above range, EPC regulates the feeder source voltage at 104% of the nominal voltage for the Radial System and 100% for the downtown Network System. This voltage regulation is achieved through the operation of automatic on-load tap changers at the EPC substation transformers. In-line capacitor-banks

[6] *CAN3-C235-83 (R2015) Preferred Voltage Levels for AC systems 0 to 50 000V*, Section 6

Table 1: Voltage Variation Limits at Service Entrance

Recommended Voltage Variation Limits at Service Entrance				
Nominal System Voltage	**Extreme Operating Conditions**	**Normal Operating Conditions**		
Single-Phase 120/240 240 480 600	106/212 212 424 530	110/220 220 440 550	125/250 250 500 625	127/254 254 508 635
Three-Phase 4-Conductor 120/208Y 240/416Y 277/480Y 347/600Y	110/190 220/380 245/424 306/530	112/194 224/388 254/440 318/550	125/216 250/432 288/500 360/625	127/220 254/440 293/508 367/635

Reference: *CSA CAN3-C235-83 (R2015) Preferred Voltage Levels for AC systems 0 to 50 000V*, Table 3

2.3 VOLTAGE UNBALANCE

The EPC Distribution System is planned to limit voltage unbalance below 4% under normal operating conditions. Voltage unbalance is measured as per the equation below[7]:

Voltage unbalance (%) = 100 x V2/V1

Variables:

V1 = average of line-to-neutral voltage on each phase
V2 = maximum deviation from V1

The DER Facility must be interconnected to the EPC Distribution System in a manner that ensures voltage unbalance can be maintained within this threshold.

2.4 FREQUENCY

The EPC Distribution System operates at 60 hertz (Hz) alternating current (AC) as part of the Alberta Interconnected Electric System (AIES) that is regulated between a range of 59.4 Hz and 60.6 Hz[8].

[7] Derived from *CAN3-C235-83 (R2015) Preferred Voltage Levels for AC Systems, 0 to 50 000 V*
[8] AESO *Generation and Load Interconnection Standard,* Table 3-1 Frequency Ranges

2.5 HARMONICS

EPC sets requirements on acceptable harmonics and flicker limits for interconnected Customers. More detailed information on these requirements can be found in the EPC Power Quality Specifications and Guidelines for Customers, Sections 2.1 to 2.6.

2.6 FAULT LEVELS

Throughout EPC's primary voltage distribution system, regardless the voltage class or geographic area, the maximum fault current level through any element on an EPC feeder cannot generally exceed 8kA, including DER generation contributions. The maximum allowable fault level can be a factor that limits the individual/aggregate size of the DER interconnection request.

2.7 GROUNDING

The EPC Distribution System is a four-wire, multi-grounded neutral (MGN) system with a Y-grounded connection. The EPC Distribution System is an effectively grounded system in accordance with the AEUC.

2.8 MAXIMUM DER FACILITY SIZE

The maximum size of a DER Facility that can be interconnected to EPC Distribution System will be assessed by EPC on a case-by-case basis when EPC receives the DER interconnection request. The maximum size varies depending on the feeder and substation where the proposed DER is interconnected. Additionally, within the same feeder/substation, detailed technical factors including: voltage class of the feeder, feeder topology, fault level, feeder and substation loading, and the existing DER penetration level in the area are considered from EPC Distribution System side and DER technologies and protection scheme from the customer side to determine the maximum interconnectable DER size.

3.0 DER FACILITY & PERFORMANCE REQUIREMENTS

This section describes the minimum design, operation and performance requirements for the DER Facility interconnecting with the EPC Distribution System.

3.1 SAFETY

EPC considers the safety of personnel and the public a top priority. All applicable electrical safety codes must be met when the DER Facility interconnects with the EPC Distribution System. The following safety requirements must be met to ensure continued interconnection with EPC's distribution system:

1. The DER Facility must be designed and operated in accordance with the applicable electrical codes and electric industry standards in effect at the time and must be interconnected and operated in a manner that does not create a safety hazard to EPC or DER Provider personnel, Customers, and the public; and
2. EPC will review the proposed design of the operating, protection, control, and metering systems that are required for the interconnection of the DER Facility. The proposed design will be approved by EPC if it is found to be compliant with EPC's interconnection requirements.

3.2 GENERAL REQUIREMENTS

The interconnection of the DER Facility must not compromise the reliability or restrict the operation of the EPC Distribution System. These reliability considerations include the following:

1. The system power quality must not be deteriorated by the interconnection and operation of the DER Facility;
2. The DER Facility must be equipped to record, measure, and report on performance related events to demonstrate compliance with the applicable sections of this document; and
3. Any DER Facility found to violate requirements 1 and/or 2 will be disconnected from the EPC Distribution System until the violation is rectified.

3.2.1 Reference Point of Applicability (RPA)

The measurement and performance requirements must be met at the location outlined in the Table 2 below. The RPA or measurement location is the point of measurement for implementing protection and control functions required for interconnection.

Table 2 - RPA Measurement Location (CSA C22.3 No.9-20 Section 7.1.2)

DER System	Measurement Location
≤30kVA	Either at the POC or at the PCC
>30kVA to ≤500kVA	EPC review and direction required
>500kVA	At the PCC[1]

[1]DER's contributing to abnormal distribution system voltages not meeting CSA C235 may require different performance requirement. Conditions which may impact DER response to abnormal voltages include DER connection through delta-wye transformers.

The DER Provider will identify, with EPC's agreement, the POC and the PCC on the project single line diagram (SLD) provided as part the DER interconnection process. For a graphical representation of these points refer to Appendix 2 - Point-of-Common-Coupling and Point-Of-Connection Reference Points.

If there is a path for zero sequence continuity between the PCC and POC and the DER facility meets conditions '1' and or '2' below the RPA may be the POC, the PCC or an agreed upon location in-between:

1) The aggregate DER nameplate is equal to or less than 500kVA and/or

2a) The annual average load demand of the facility as calculated by EPC is less than 10% of the aggregate DER nameplate ratings

AND

2b) The site is prevented or not capable of exporting more than 500kVA for longer than 30 seconds.

DER sites meeting either or both conditions above but with no path for zero sequence continuity between the PCC and POC must be able to detect area power system faults and open phase conditions at an appropriate agreed upon location as per IEEE 1547-2018 Subsections:

- 4.2 Reference Points of Applicability (RPA),
- 6.2 Area EPS Faults and Open Phase Conditions, and
- 6.4 Voltage.

All other performance requirements shall be met at the POC or at a mutually agreed point in-between the POC and PCC.

3.2.2 PCC & DER Isolation Device

The DER Facility must be able to disconnect from the EPC Distribution System using at least one electrical isolation device(s).

1. The electrical isolation device must comply with *CSA C22.1-21 Canadian Electrical Code Part I*
2. DER systems, or systems with multiple DER units must have one disconnect means with the capability of isolating all DER units simultaneously and the following:
    1. Capable of being de-energized from both the EPC Distribution System and the DER within the DER Facility;
    2. Able to visually confirm if the isolation device is in the open or closed position;
    3. Able to visually verify that the contacts are open (visible break);
    4. Capable of being operated at rated load;
    5. Capable of being physically locked in the open position;
    6. Have a manual override;
    7. Capable of being operated with a fault on the system;
    8. Not expose the operator to any live parts; and
    9. Bear a physical warning label that indicates the device can be energized from sources on both sides.
3. Isolation devices within DER Facilities rated in aggregated nameplate (in aggregate) 2MVA or greater, or DER Facilities that require Direct Transfer Trip(DTT) *[see Active Anti-Islanding Protection – Direct Transfer Trip (DTT)]*, shall be remotely electronically operatable by EPC. ENMAX may require this functionality for smaller DER as determined on a case-by-case basis. These isolation devices can be either spring-operated, motorized, or equivalent.

4. EPC may require an isolation device to be installed between the EPC Distribution System and the DER Facility, upstream of all transformers, DERs, and high-voltage (HV) ground sources. In this case the isolation device must be able to meet the following requirements:
    - Be readily accessible by EPC;
    - Lockable by EPC in an open position;
    - Not having any keyed interlocks;
    - The DER Provider and EPC mutually agreeing to the exact location of the disconnect switch; and
    - All motorized isolation devices to be powered from a reliable source, such as a direct current (DC) battery to power a DC motor, or via a battery-supplied direct current DC/AC inverter to power an AC motor; and

    The DER Provider must coordinate all switching, tagging and lockout procedures with EPC.

5. DER that are larger than 2MVA in aggregate nameplate, or smaller as required by EPC, shall require an isolation device installed upstream of the DER facility's PCC and within the EPC Distribution System for isolation of the entire DER facility and possibly any loads also within the PCC of the site where the DER facility is located. For such cases, the following will be required at the cost of the DER Provider:
    1. A three phase ganged-operation isolating switch[9] for each EPC Distribution System feeder supplying the DER facility.
    2. For sites larger than 4MVA in aggregate nameplate or as required by EPC, the three phase ganged-operation isolating switch shall be an automated recloser capable of remote controlled operation, tripping, and be programmed with protection and control settings that can also mirror the DER facility's settings with or without a time delay.

        ENMAX Power has can change the utility isolation device as required per specific site requirements. This is will be evaluated for all DER units that are primary metered or over 1.5MW in aggregate rating.

6. The interconnected DER Facility must disconnect all DERs from the EPC Distribution System under the following circumstances:
    - If the configuration change differs from what was studied and approved in the DER Facility's System Impact Assessment (SIA), or
    - Direction by the EPC System Control Centre, or
    - If operation of an EPC-owned, manual-operated air break switch is required, the DER must be disconnected from the EPC Distribution System as directed by the EPC System Control Centre.

[9] The make, model, and design of the three phase ganged-operation isolating switch will be specified by EPC.

3.2.3 DER Interconnection Ride-Through Capability

To limit system impact due to customer owned generation tripping during system disturbances, DER(s) shall meet certain disturbance ride-through capabilities defined below:

3.2.3.1 Machine based DER

The Baseline grade capabilities as described in CSA C22.3 NO.9-20 align with IEEE-1547-2018 Category 1 requirements. In general, machine based DER are not capable of the fast response required to meet IEEE-1547-2018 Category 2 and 3. EPC requires all machine based DER to meet the baseline capability requirements as described in CSA C22.3 NO.9-20 to align with the AESO DER Ride-Through Performance Recommendations. Machine based DER are required to meet the Default Settings as outlined in Table 3 and the requirements in Table 5 below:

Table 3 – Voltage ride-through – Baseline Grade (CSA C22.3 No.9-20)

Voltage range (% of nominal voltage)	Minimum ride-through time (s) (design criteria)	Maximum response time (s) (design criteria)	Response
V > 120	N/A*	0.16	Cease to energize
117.5 < V ≤ 120	0.2	N/A	Mandatory operation
115 < V ≤ 117.5	0.5	N/A	Mandatory operation
110 < V ≤ 115	1	N/A	Mandatory operation
88 ≤ V ≤ 110	Infinite	N/A	Continuous operation
70 ≤ V < 88	Linear slope of 4s/1p.u. voltage starting at 0.7s @ 0.7 p.u.: T_{VTR} = 0.7s + (4s / 1p.u.)* (V – 0.7 $p.u.$)	N/A	Mandatory operation
50 ≤ V < 70	0.16	N/A	Mandatory operation
V < 50	N/A*	0.16	Cease to energize

* Cessation of current of DER in not more than the maximum specified time and with no intentional delay. This does not necessarily imply disconnection, isolation, or a trip of the DER.

Reference: CSA C22.3 No.9:20 Interconnection of Distributed Energy Resources and Electricity Supply Systems section 7.4.6.5 Voltage ride-through – Baseline Grade Table 12

3.2.3.2 Inverter based DER

The Supplemental grade capabilities as described in CSA C22.3 NO.9-20 align with IEEE-1547-2018 Category 2 requirements. All inverter based DER shall meet the Supplemental Capabilities as described in this CSA C22.3 NO.9-20 in order to align with the AESO DER Ride-Through Performance Recommendations. Inverter based DER are required to meet the Default Settings as outlined in Table 4 and the requirements in Table 5 below:

Table 4 – Voltage ride-through – Supplemental Grade (CSA C22.3 No.9-20)

Voltage range (% of nominal voltage)	Minimum ride-through time (s) (design criteria)	Maximum response time (s) (design criteria)	Response
V > 120	N/A*	0.16	Cease to energize
117.5 < V ≤ 120	0.2	N/A	Mandatory operation
115 < V ≤ 117.5	0.5	N/A	Mandatory operation
110 < V ≤ 115	1	N/A	Mandatory operation
88 ≤ V ≤ 110	Infinite	N/A	Continuous operation
65 ≤ V < 88	Linear slope of 8.7s/1p.u. voltage starting at 3s @ 0.65 p.u.: T_{VTR} = 3s +(8.7s / 1p.u.)* (V – 0.65 $p.u.$)	N/A	Mandatory operation
45 ≤ V < 65	0.32	N/A	Mandatory operation
30 ≤ V < 45	0.16	N/A	Mandatory operation
V < 30	N/A*	0.16	Cease to energize

* Cessation of current of DER in not more than the maximum specified time and with no intentional delay. This does not necessarily imply disconnection, isolation, or a trip of the DER

Reference: CSA C22.3 No.9:20 Interconnection of Distributed Energy Resources and Electricity Supply Systems section 7.4.6.5 Voltage ride-through – Supplemental Grade Table 13

Table 5 – Frequency ride-through for Baseline and Supplemental Grade (CSA C22.3 No.9-20)

Frequency range (Hz)	Minimum ride-through time (s) (design criteria)
f > 62.0	N/A
61.2 < f ≤ 62.0	299
58.8 < f ≤ 61.2	Infinite*
57.0 < f ≤ 58.8	299
f ≤ 57.0	N/A

* Applicable only for a per-unit ratio of voltage/frequency limit of V/f ≤ 1.1.

Reference: CSA C22.3 No.9:20 Interconnection of Distributed Energy Resources and Electricity Supply Systems section 7.4.6.5 Frequency ride-through – Baseline and supplemental grades Table 14

3.3 FREQUENCY-DROOP

AESO has published requirements for frequency droop within its April 2025 Distributed Energy Resources Primary Frequency Response Guideline [https://www.aeso.ca/assets/DER-Primary-Frequency-Response.pdf]. As per this guideline DERs in aggregate capacity of 5MVA or greater are required to implement frequency-droop as outlined from AESO's guideline:

TABLE 3: Parameters of Frequency-Droop (Frequency/Power) for DERs

Parameter	Default settings
db_{OF}, db_{UF} (Hz)	0.036
k_{OF}, k_{UF}	0.05
$T_{response}$ (s)	5

The active power output shall be as defined by the following equation, until frequency returns to within the deadband:

$$P_{\square}(f) = \begin{Bmatrix} max\{Ppre - \dfrac{f-(60+dbOF)}{60\times kOF}; Pmin\} & f > 60 + db_{OF} \\ min\{Ppre + \dfrac{(60-dbUF)-f}{60\times kUF}; Pavl\} & f < 60 - db_{UF} \end{Bmatrix}$$

where

$P(f)$ is the active power output in p.u. of the DER nameplate active power rating as a function of the disturbed system frequency in Hz

f is the disturbed frequency or applicable frequency in Hz

P_{avl} is the available active power in p.u. of the DER rating

P_{pre} is the pre-disturbance active power output, defined by the active power output at the point of time the frequency exceeds the deadband in p.u. of the DER rating

P_{min} is the minimum active power output due to DER prime mover constraints, in p.u. of the DER active power rating in kW

db_{OF} is the single-sided deadband value for high-frequency, in Hz

db_{UF} is the single-sided deadband value for low-frequency, in Hz

k_{OF} is the per-unit frequency change corresponding to 1 per-unit power output change (frequency droop) and is a constant droop for over-frequency events

k_{UF} is the per-unit frequency change corresponding to 1 per-unit power output change (frequency droop) and is a constant droop for under-frequency events

Excerpts from AESO DER Primary Frequency Response Guideline, April 2025

The standard requires that the DER response shall conform to the prioritization of DER responses specified in clause 4.7. This is ensured by testing the DERs to IEEE 1547.1-2020 – IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Energy Resources with Electric Power Systems and Associated Interfaces (IEEE 1547.1-2020) "Test standard." The DER returns to its pre-disturbance operating mode after responding to the disturbance, which could be one of these mutually exclusive modes: constant power factor mode, voltage reactive power mode, active power reactive power mode, and constant reactive power mode."

3.4 POWER QUALITY

The DER Facility must meet the following requirements to ensure that the high quality of electrical service is maintained to all Customers.

When deemed required by EPC, EPC will undertake a System Impact Assessment (SIA) to ensure compliance with the goals of this TIR. It will also determine if any additional requirements unique to the proposed DER Facility, distribution system, proposed connection type or any combination thereof exist to ensure compliance to ensure EPC can maintain the stated objectives in Section 1.1.

Please note, studies may have to be reconducted, at the sole cost of the DER Facility Owner, if the DER Facility changes major equipment or operational theory (e.g., changes to POC, size of DER, type of DER, interconnection transformer, changes to SLD, changes in planned operating mode, etc.). This re-study can also lead to additional delays in the interconnection of the DER Facility.

3.4.1 Voltage Regulation

The operation of the DER Facility must not cause a voltage violation, as defined in Table 1 of subsection 2.2, on any part of the EPC Distribution System. The DER Facility must not regulate voltage at the PCC unless otherwise previously approved by EPC. The startup and shut down of the DER Facility must be done in a manner that allows the EPC substation on-load tap changer to adjust voltage to ensure it is within the appropriate limits.

To meet the voltage regulation requirements, the DER Facility must, at minimum, implement the following control methods:

1. Induction Generation:
    - Induction generation rated in aggregate ≥150kW may be required to provide reactive power compensation to maintain a generation output power factor of 90%, leading[10] or better, at full rated power output; and
    - If the selected reactive power compensation rating matches or exceeds the limit for self-excitation of the generator, provisions must exist in the design and operation of the DER Facility to disconnect the compensation equipment when a fault occurs on the EPC Distribution System.
    - At minimum volt-watt mode is required for this category (Category A) of DER

2. Synchronous Generation:

[10] A leading power factor for generation means that reactive power is absorbed by the DER Facility from the EPC Distribution System.

- Synchronous generation rated in aggregate ≥30kW must be able to operate continuously at any power factor between 90% lagging and 90% leading at full-rated power output. EPC will determine the actual set-point between these limits on a case-by-case basis;
- DER operation in power factor control mode must meet the following requirements:
    - The maximum DER response time to the deviation of power factor to restore the set power factor must be 10 seconds or less; and
    - Control schemes for the excitation control system of the generator that reduce excitation current must be made whenever an overvoltage exceeding the voltage regulation criteria is detected at either the generator terminal or the PCC; and
- At minimum volt-watt mode is required for this category (Category A) of DER
- In some cases, DER operation in voltage control mode may be required to be implemented in lieu of power factor control mode. EPC will determine the need for this requirement on a case-by-case basis. If determined necessary, voltage control mode must be able to meet the following requirements:
    - Maintaining voltage at the PCC within the voltage regulation criteria year-round; and
    - Having a time delay function with the provision to adjust the delay between 0 and 180 seconds. EPC will determine the actual time-delay required on a case-by-case basis.

3. Inverter-based Generation:
    - Constant power factor mode with unity power factor setting must be the default mode of the installed DER unless otherwise previously specified by EPC; and
    - The DER Facility must not inject DC current greater than 0.5% of the full rated output current at the DER inverter AC output terminals.
4. When determined necessary by EPC, the DER Provider must either operate the DER within a larger range of power factor control or implement more active voltage regulation modes, such as volt-var and/or volt-watt control and adjustable constant reactive power (see subsection 3.5) . EPC will determine the details of this requirement on a case-by-case project basis.

3.4.2 Voltage Unbalance

The DER Facility must not adversely affect the EPC Distribution System voltage balance among three phases and must be able to operate under the existing feeder voltage unbalance conditions. The interconnection of a single or three-phase DER Facility must not result in a violation of the voltage unbalance limits specified in subsection 2.3.

3.4.3 Duration required before a DER can Enter Service

In alignment with IEEE 1547-2018, the enter service duration shall be 300s (seconds) unless otherwise determined and accepted by EPC. DER shall not energize the ENMAX Distribution System until applicable voltage and system frequency are within ranges specified in Table of IEEE 1547-2018 and the permit service setting is set to “Enabled”.

Table 4—Enter service criteria for DER of Category I, Category II, and Category III

Enter service criteria		Default settings	Ranges of allowable settings
Permit service		Enabled	Enabled/Disabled
Applicable voltage within range	Minimum value	≥ 0.917 p.u.[a]	0.88 p.u. to 0.95 p.u.
	Maximum value	≤ 1.05 p.u.	1.05 p.u. to 1.06 p.u.
Frequency within range	Minimum value	≥ 59.5 Hz	59.0 Hz to 59.9 Hz
	Maximum value	≤ 60.1 Hz	60.1 Hz to 61.0 Hz

Reference: IEEE 1547-2018, Section 4.10.2, Table 4. Values to be in reference to CSA CAN3-235.

3.4.4 Maximum active power ramp rate for entering service

The maximum active power increase over the enter service duration shall be less than or equal to 20% of the DER nameplate active power rating per minute.

Where a stepwise ramp is used, the rate of change over the period between any two consecutive steps shall not exceed the average rate-of-change over the full enter service period. This requirement is a maximum ramp rate requirement and the DER may increase output slower than specified.

DER shall not operate at a faster ramp rate unless it has been allowed by EPC specifically for that DER facility. If a DER Provider plans to design their DER facility to operate at a faster ramp rate, they need to first seek and receive permission from EPC before they can begin to design the plant to operate faster than this maximum ramp rate.

To verify whether a fast ramp rate can be used, EPC will need to complete additional interconnection studies including electro-magnetic transient (EMT) studies to understand the impact of a higher ramp rate. Such a study will take at least 8 months to complete and may require additional equipment to be installed and/or additional operational requirements for the DER facility.

3.4.5 Voltage Flicker/Fluctuation and Harmonics

Harmonics can cause transformer and motor thermal overheating, communication system interference, electronic device failure, and resonant overvoltages. Similarly, the combination of change in voltage magnitude, and the frequency of voltage changes, can produce an objectionable voltage fluctuation on the EPC Distribution System. To ensure the safe and reliable operation of the EPC Distribution System and all Customer equipment, the DER Facility must comply with the requirements described in *ENMAX Power Quality Specifications and Guidelines for Customers*[11].

3.5 ACTIVE & REACTIVE POWER REQUIREMENTS

The DER Facility must meet the following active and reactive power requirements:

1. Power delivery must not exceed the Maximum Allowable Export Capability (MAEC), permitted by EPC upon completion of the SIA; and

[11] Guidelines for operation of a DER Facility and its final acceptance by EPC.

2. Reactive power must be controlled to comply with the voltage and power factor requirements described in subsection 2.2, as well as all requirements described in the Operating Procedures.
3. Reactive power capabilities are to align with capability requirements outlined in Alberta IEEE 1547-2018 section 5.
4. Where required, to respect apparent power limitations of a DER facility, active power is to be curtailed to ensure that reactive power requirements are met at any given time. This is also known as reactive power priority or “Q priority” mode.
5. Typical reactive power control function required is Constant power factor mode with unity power factor. As determined by ENMAX Power, DER facilities shall use Voltage-reactive power (volt-var) mode, Active power-reactive power mode, or Constant reactive power mode or a combination of these four modes as determined by EPC.
    a. Any or all of these four modes shall, as determined by EPC, be used in combination with Voltage-active power (volt-watt) mode.
    b. Typical application of volt-var and volt-watt modes can be found in Appendix 6
6. Volt-var mode used in combination with volt-watt mode is required for all DERs with aggregate active power nameplates of 5MW or greater, unless otherwise determined by ENMAX Power. This requirement shall also apply as determined by EPC for smaller DER facilities. If interconnection studies identify that these modes are not sufficient to mitigate reactive power impacts from the DER’s interconnection, then further design requirements for the DER facility may be required. Requirements may include reactive power technologies within or outside of the DER facility as determined in the interconnection studies. Any additional requirements shall be implemented at the DER Provider’s cost.

3.6 EQUIPMENT RATINGS & REQUIREMENTS

The DER Facility equipment must meet the following ratings and requirements:

1. Comply with the applicable regulations, codes, AUC rules and CSA, Canadian Electricity Association (CEA), IEEE, and EPC equipment standards;
2. Be maintained to ensure all performance requirements in this document are met;
3. Not exceed EPC’s equipment ratings; and
4. Where required by EPC, upgrade or replace all regulating devices and metering devices, designed for unidirectional power flow to ensure the DER Facility is capable of handling bidirectional power flow.
5. For DER Facilities with 500kW or larger aggregate, PCC and POC interrupting devices shall be required to take into consideration external trip requirements and status indication requirements. For example, molded case circuit breakers used for disconnect means may require shunt trip and 52a/b status contacts which are not typically standard equipment.

3.6.1 Interrupting Device Rating

All fault current interrupting devices must be rated according to both the fault levels of the EPC Distribution System and the DER Facility fault level contribution. The interrupting device used to disconnect the DER from the EPC Distribution System must operate fast enough to meet the timing requirement of the quickest protection element.

3.6.2 Surge Withstand

The protection, control, and communication equipment of the DER Facility interconnection system must not fail, mis-operate, or provide misinformation due to voltage or current surges. The DER Facility's interconnection system must have the capability to withstand voltage and current surges in accordance with the environments defined in the following IEEE and CSA standards:

- *IEEE/ANSI Std. C62.41.2 IEEE Recommended Practice on Characterization of Surges in Low-Voltage (1000 V and Less) AC Power Circuits;*
- *IEEE Std. C37.90.1 IEEE Standard for Surge Withstand Capability (SWC) Tests for Relays and Relay Systems Associated with Electric Power Apparatus – Description; and*
- *CAN/CSA-C60044-6:2011 Instrument Transformers Part 6: Requirements for Protective Current Transformers for Transient Performance* or *IEEE Std C57.13:2016 – IEEE Standard Requirements for Instrument Transformers*.

3.7 FERRORESONANCE

EPC requires that ferroresonance and other types of resonance be considered in the design of the DER Facility. If resonance problems arise, the DER Provider in collaboration with EPC must conduct a comprehensive study to determine the cause and mitigate the effects. The DER Provider will demonstrate mitigation by providing a written report to EPC.

3.8 PHASING

The DER Facility must connect rotating machines, as required, to match the phase sequence and direction of rotation of the EPC Distribution System.

3.9 INTERCONNECTION TRANSFORMER

An interconnection transformer may be located between the PCC and the DER Facility and is used to step-up or step-down the DER's voltage for the interconnection with the EPC Distribution System. The transformer selection affects voltage regulation, fault current contribution, and harmonic current flow on the EPC Distribution System. If an interconnected transformer is required, the following restrictions must be implemented by the DER Provider:

1. The DER interconnection transformer must not cause voltage disturbances or disrupt co-ordination of distribution system ground fault protection;
2. The typical interconnection transformer connection is a grounded-*wye* on the EPC Distribution System side and *delta* on the DER Facility side. If the DER Provider proposes other types of interconnection, EPC will review and approve the proposal on a case-by-case project basis. For a list of advantages and disadvantages for a variety of transformer winding configurations, please refer to CSA C22.3 NO.9-20 Annex C; and
3. Interconnection transformers are required to have off-load tap changers on their primary (high voltage) side with a minimum range of +/- 2.5% of rated voltage.

3.10 SYSTEM GROUNDING

The DER Facility must be effectively grounded pursuant CEC 22.1 and/or *IEEE Std. 142 – IEEE Recommend Practice for Grounding of Industrial and Commercial Power Systems*.

DER Providers are required to provide documentation confirming their system is effectively grounded as per applicable standards. This will be at least required for any synchronous machine DER and inverter based DER over 500kW in aggregate. EPC is required to review and accept the grounding studies prior to DER facility construction beginning.

DER Providers are required to provide documentation of the DER facility's effectively grounded equipment and proper installation. ENMAX may require on-site inspection of any and all additional equipment that are determined necessary to mitigate overvoltage and ensure effective grounding.

EPC reserves the right at any time to request a report confirming effective grounding. In addition, any studies required to ensure that Ground Potential Rise meets step and touch potential must also be submitted together to EPC with the effective grounding report.

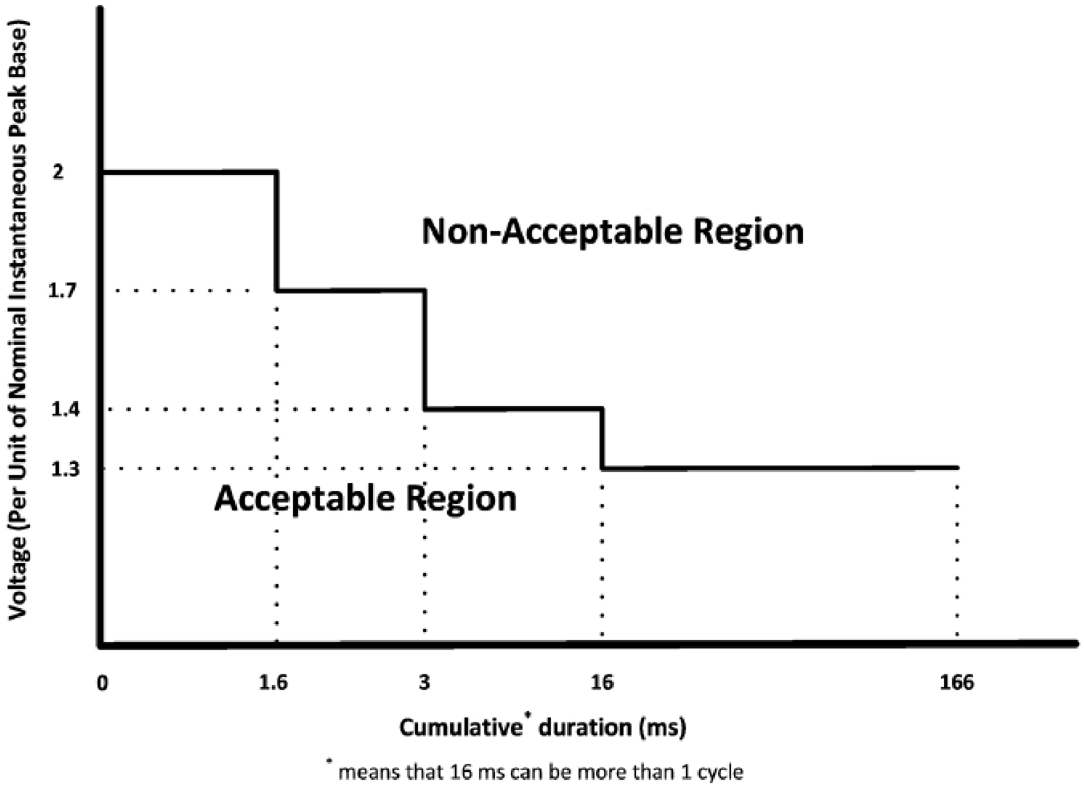
3.11 NEUTRAL GROUNDING

DERs are often connected through a step-up transformer. Based on transformer configuration, facility isolating devices and isolation schemes, it is possible to create ungrounded zones within the Utility and/or customer distribution systems. These ungrounded zones pose risk to safety and equipment in the form of transient over-voltages and non-detection zones. The customer shall design neutral grounding solutions in accordance with the following as applicable:

- CSA 22.1-24 Canadian electrical code
- IEEE C62.92.1 IEEE Guide for the Application of Neutral Grounding in Electrical Utility Systems, Part 1 – Introduction; and
- IEEE C62.2 IEEE Guide for the Application of Neutral Grounding in Electrical Utility Systems, Part II - Grounding of Synchronous Generator Systems.
- IEEE C62.6 IEEE Guide for the Application of Neutral Grounding in Electrical Utility Systems, Part II – Supplied by current regulated sources.

Neutral grounding shall be considered to ensure voltage ratings of equipment and surge protection device ratings are not exceeded (see Figure 4 below).

Figure 4 - IEEE1547-2018 Section 7.4.2 Limitations of Cumulative Instantaneous Overvoltage



Reference: IEEE 1547-2018, Section 7.4.2, Figure 3

3.12 BATTERIES / DC SUPPLY

The DER Facility must include battery backup systems[12] to meet the following requirements:

1. All protective devices must have battery backup systems to ensure operation of all protective functions in the event of a power failure for the appropriate time required to fully disconnect the DER Facility from the EPC Distribution System;
2. All battery backup systems must be capable of sustaining Supervisory Control and Data Acquisition (SCADA) and telecommunications equipment to prevent telemetry outages between the DER Facility and the EPC System Control Centre for a minimum of eight hours;
3. In the event of a failure of the battery backup system or the battery voltage, the protection scheme will be considered failed and the DER(s) and HV ground sources will be disconnected from the EPC Distribution System; and
4. Relays connected to the DC supply must not be subject to sustained overvoltage if there is a possibility that the DC rating of the equipment will be exceeded. To prevent this, steps must be

[12] Batteries and chargers must be connected to the main service supply or by using an uninterruptable power supply with sufficient capacity for the application.

taken by the DER Provider to ensure that the DC voltage limiting devices are installed at each relay.

3.13 POWER EXPORT INTO EPC SUBSTATIONS

If a Distributed Energy Resource (DER) is determined large enough to export power into a EPC substation transformer, that DER facility will require additional interconnection studies. For example, if the active power produced by the DER facility exceeds the minimum load demand on the substation transformer, EPC will require additional studies from the transformer manufacturer to assess the impact on the substation transformer.

When such studies are required, the DER Provider will be required to pay the costs for these studies and EPC will let the customer know if their project can proceed as requested or not. Note, that such studies can result in alternations to DER facility or ENMAX Distribution System equipment and/or additional operational requirements for the DER facility.

3.14 POWER EXPORT FROM ELECTRIC VEHICLES

Any requests for use of an electric vehicle to export power back into the ENMAX Distribution System require a detailed review by EPC to allow the interconnection and operation.

If interconnection is not allowed by EPC, the electric vehicle shall only import power as a load to charge its internal energy storage system. Additionally, if interconnection is not allowed for export, additional protection systems (such as an automatic transfer switch) may be required within the DER facility to ensure any electric vehicle cannot interconnect in parallel with the ENMAX Distribution System. All interconnection costs would be paid by the requesting customer or DER Provider.

3.15 THEORY OF OPERATION SITES WITH SIGNIFICANT, COMPLEX DER OR MULTIPLE SOURCES

A Theory of Operation or sequence of operation is required for all DER that are in aggregate over 1,000 kVA and/or have multiple energy sources and/or have Battery Energy Storage System(BESS) technologies. DER needing to provide this includes, but is not limited to, Battery Energy Storage Systems(BESS), microgrids, virtual power plants, hybrid DER(Solar PV coupled with BESS), or sites with multiple EPC Distribution System sources.

Additionally, solar PV DER that are supplied from a single ENMAX source and with nameplate in aggregate over 1,000 kVA in size also are required to provide a theory of operation. ENMAX Power reserves the right to request this for any DER interconnection where it is deemed necessary and the DER Provider shall provide this prior to equipment being ordered.

3.16 ELECTRO-MAGNETIC TRANSIENT STUDIES

When determined necessary by EPC, DER Providers will provide Electro-Magnetic Transient (EMT) studies for their DER facility. Such a study will take at least 8 months to complete and may require additional equipment to be installed and/or additional operational requirements for the DER facility.

4.0 PROTECTION & CONTROL REQUIREMENTS

This section describes the protection and control requirements for DER Facility interconnection with the EPC Distribution System. These requirements ensure the isolation of all DERs to limit damage to equipment and protect EPC personnel, the DER Facility and DER Provider personnel.

4.1 PROTECTION DEVICE REQUIREMENTS

The following requirements pertain to the protection and control devices:

1. Protection relays must meet all applicable standards for the location and application for which they are installed which may include but is not limited to:
    - Underwriters Laboratories (UL);
    - CSA (including CSA 22.3 No.9-20);
    - IEC;
    - IEEE; and
    - European Standard, European Pre-Standard (EN and ENV);
2. The protection devices and related systems must remain operational for the duration of the following:
    - For any disturbance which the DER must operate until the DER has been isolated, including:
        - All faults within the DER Facility's distribution system; and
        - All faults on the interconnecting EPC feeder and upstream distribution equipment; and
    - Loss of power supply from the EPC Distribution System prior to any automatic distribution or transmission system restoration;
3. Protection devices must be failsafe, isolating the DER in the event of a protection device failure;
4. All protection element requirements must be met at the PCC unless otherwise stated in the Technical Requirements;
5. Use of interlocks between protection elements and the position of any isolation device, or DER status, must be proposed to EPC for review and acceptance;
6. Total clearing time must be measured from the inception of the fault condition to the time the DER is disconnected from the EPC Distribution System; and
7. Additional protection elements, other than those listed in this section or as described in the *AUC Micro-generation or Distributed Generation guidelines (such as the Micro-Generation Notice Submission Guideline*), may be required as determined by EPC.

For more information refer to Appendix 3 – DER Single Line Diagram for the Primary and Secondary Interconnection.

4.2 PROTECTION REQUIREMENTS for DERs IN PARALLEL FOR 6 CYCLES OR LESS (CLOSED TRANSITION) OR OPEN TRANSITION

This section is only be applicable to any DER or DER facilities which are in parallel for 6 cycles or less (closed transition) or open transition. Such DER facilities are considered to be non-parallel, non-export DER facilities.

Synchronization systems, where required, must follow the requirements outlined in subsection 4.11.

The DER Facility connecting for 6 cycles or less must include the following:

- Undervoltage protection to ensure that the generator is not capable of energizing the EPC Distribution System if the system is de-energized; and
- A failsafe operation to ensure that the DER Facility will not operate in-parallel with the EPC Distribution System for more than 30 cycles.

4.3 MINUMUM PROTECTION REQUIREMENTS

The protection elements listed as follows are required for the DER Facility operating in parallel non-export and parallel-export modes:

- Undervoltage;
- Overvoltage;
- Underfrequency;
- Overfrequency; and
- Overcurrent.

Additional protection elements may be required based on the DER protection configuration and interconnection system characteristics and DER modes of operation.

4.4 SENSITIVITY AND COORDINATION

The DER Facility protection scheme must be able to detect and clear abnormal conditions as described below. The protection schemes must detect and clear, but not be limited to, the following conditions:

- Balanced and unbalanced faults within the DER Facility and on the EPC Distribution System;
- Abnormal frequencies (refer to Table 6);
- Abnormal voltages (refer to Table 7 and Table 8);
- Islanding conditions; and
- DER Facility equipment malfunction and failure; and

The protection elements and time delays required as per the Technical Requirements must coordinate with EPC protection and control schemes.

4.5 PROTECTION OPERATING TIMES

DER Facility protection elements must disconnect from the EPC Distribution System within the required times based on, but not limited to, the following:

1. Overcurrent coordination at the PCC pursuant to subsection 4.6;
2. Over/undervoltage ride through and disturbances pursuant to subsection 4.10;
3. Over/underfrequency ride through and disturbances pursuant to subsection 4.9; and
4. Loss of utility supply. EPC Transmission and Distribution System conductors use automatic line reclosing to increase system reliability. The DER Facility's protection elements must coordinate with all upstream automatic reclosing schemes. In general, fault detection time, protection operate time, breaker operate time and safety margin must total less than 1.5 seconds. Elements may include, but not be limited to the following pursuant to subsection 4.6:
    - Directional power, reverse or minimum import (site specific);
    - Directional over-current;
    - Rate of change of frequency; and
    - Vector shift and
    - Direct Transfer Trip

4.6 PHASE & GROUND FAULT PROTECTION

The DER Facility is required to meet the following phase and ground fault protection requirements:

1. The DER Facility protection scheme must disconnect the DER from the EPC Distribution System under the following conditions:
    - All faults within the DER Facility's distribution system; and
    - All faults on the interconnecting EPC feeder and distribution equipment;
    - Loss of EPC utility supply to the DER facility.
2. Phase and ground fault protection elements at the PCC must always be operational when the fault current can be sourced from the EPC Distribution System;
3. The DER protection scheme must detect and clear ground faults where there is no path for zero sequence components between the DER and point of common coupling;
4. Protective device element settings must consider present and future anticipated fault current including the DER fault contribution;
5. The protective device selectivity must be able to detect faults on the EPC Distribution System and disable automatic reclosing of the DER;
6. Upon request by the DER Provider, EPC will provide the system phase and ground fault currents and X/R ratios without the concerned DER Facility interconnected; and
7. For those cases where the fault contribution to the EPC Distribution System from the DER is sufficient to melt EPC-owned fuses, a 200-millisecond clearing time interval is required.

It may not be possible for the DER Facility protection elements to detect faults on the EPC Distribution System prior to EPC protection operating due to the reduction of fault currents from sources caused by in-feed effect. Therefore, the DER Facility protection elements must factor in the natural decay of fault contribution from the DER, such as direct-connected rotating drivers.

4.7 Open Phase Protection

The DER Facility's protection scheme must be able to detect the loss of any phase[13] both within the DER Facility or on the EPC Distribution System.

Once an open-phase condition is detected, the DER protection scheme must:

- Disconnect the DER from the EPC Distribution System taking into account any EPC upstream automatic reclosing devices; and
- Disconnect the DER step-up transformer, if applicable, when the transformer is three-phase with a common (shared) magnetic core to prevent phantom voltages on the open phase.

It is advised that DER providers use three phase DER for three phase supplied services.

4.8 Feeder Relay Directional Protection

The DER Facility over-current protection must coordinate with the closest upstream EPC protection which could be the substation feeder breaker or an interrupting device such as a fuse or switch.

4.9 Over / Underfrequency Protection

The DER Facility is required to meet the following over/underfrequency protection requirements:

- Abnormal frequencies must be detected and isolated according to Table 6;
  - The minimum frequency tripping requirements for all DERs are the Default Settings in Table 6.
- Clearing times must not be less than those listed under the default settings range and not greater than the time listed under the range of adjustability;
- The DER rated in aggregate >30kW must have the frequency set-points field adjustable; and
- The DER rated in aggregate ≤30kW may have the frequency set-points fixed or field adjustable.

Table 6: Over/Under Frequency Protection Response

Default Settings			Ranges of Adjustability	
Function	**Frequency (Hz)**	**Clearing Time (s)**	**Frequency (Hz)**	**Clearing Time (s)**
OF2	62.0	0.16	61.8-66.0	0.16 - 1000
OF1	61.2	300	61.0-66.0	180 - 1000
UF1	58.5	300	50.0-59.0	180 - 1000
UF2	56.5	0.16	50.0-57.0	0.16 - 1000

[13]Detection and isolation of equipment for loss of phase is to prevent uncontrolled voltages on phases that have been disconnected from the EPC Distribution System. Energizing open-phase conductors through a common magnetic core may cause abnormal and uncontrolled voltages. In some instances, ferroresonance may cause extreme overvoltages.

Reference: CSA C22.3 No.9:20 Interconnection of Distributed Energy Resources and Electricity Supply Systems section 7.4.6.3 Over-frequency and Under-frequency Protection Table 9.

4.10 Over / Undervoltage Protection

The DER Facility is required to meet the following over/undervoltage protection requirements:

- The DER must detect and cease to energize past the PCC for voltages and durations that fall outside of the ranges listed in Table 7 and/or Table 8, as applicable;
    - The minimum voltage tripping requirements for all DERs are the Default Settings in Tables 7 (for machine-based DER) & 8 (for Inverter-based DER) as applicable.
- The DER voltage must be measured as follows:
    - Phase-to-neutral for single-phase generators;
    - Phase-to-neutral for solidly grounded *wye-wye* transformer configurations;
    - Phase-to-neutral where loss of Utility results in loss of ground reference; and
    - Phase-to-phase for all other installations;
- Voltages must be detected at the PCC unless otherwise stated in the Technical Requirements or a previously approved by EPC;
- Changes to clearing times may be required as detailed in the initial SIA;
- The DER rated in aggregate >30kW must have the voltage set-points field adjustable;
- The DER rated in aggregate ≤30kW may have the voltage set-points fixed or field adjustable; and
- Ferroresonance and self-excitation conditions may require the implementation of instantaneous voltage elements.

Table 7: Over/Undervoltage Protection Response – CSA C22.3 No.9:20 Baseline Grade

Default Settings			Ranges of Adjustability	
Function	**Voltage (% of nominal)**	**Clearing Time (s)**	**Voltage (% of nominal)**	**Clearing Time (s)**
OV2	120	0.16	N/A	N/A
OV1	110	2.0	110 - 120	1.0 – 13.0
UV1	88	2.0	0 - 88	2.0 – 21.0
UV2	45	0.16	0 - 50	0.16 – 2.0

Reference: CSA C22.3 No.9:20 Interconnection of Distributed Energy Resources and Electricity Supply Systems section 7.4.6.4 Over-voltage and Under-voltage Protection Table 10

Table 8: Over/Undervoltage Protection Response – CSA C22.3 No.9:20 Supplemental Grade

Default Settings			Ranges of Adjustability	
Function	**Voltage (% of nominal)**	**Clearing Time (s)**	**Voltage (% of nominal)**	**Clearing Time (s)**
OV2	120	0.16	N/A	N/A

OV1	110	2.0	110 - 120	1.0 – 13.0
UV1	88	10.0	0 - 88	2.0 – 21.0
UV2	45	0.16	0 - 50	0.16 – 2.0

Reference: CSA C22.3 No.9:20 Interconnection of Distributed Energy Resources and Electricity Supply Systems section 7.4.6.4 Over-voltage and Under-voltage Protection Table 11

4.11 Synchronization

An approved automatic synchronizer and synchronization blocking device is required for the DER to ensure that the DER Facility does not connect to energized EPC equipment out-of-phase;

Interconnection of the DER Facility will be blocked or otherwise prevented if the EPC Distribution System power supply is outside the normal operating range. DERs capable of self-excitation must only interconnect once the frequency, voltage, and phase angle are within the ranges listed in Table 9.

DERs that do not produce fundamental voltages, such as grid-following inverter-based DER, induction machines, and double-fed machines with excitation systems controlled by electronics that match the supply voltage magnitude, frequency and phase angle may use this functionality to achieve synchronization requirements.

Synchronizing schemes must be submitted to EPC for review and approval prior to installation. DER Facility synchronizing schemes must also take into consideration automatic reclosing on EPC Distribution System Facilities.

Table 9: Synchronization Requirements

Aggregate Rating of Generators (kW)	Frequency Difference (Δ f, Hz)	Voltage Difference (Δ V, %)	Phase Angle Difference (Δ Φ, %)
0-500	0.3	10	20
>500 – 1500	0.2	5	15
>1500	0.1	3	10

Reference: *IEEE 1547-2018, IEEE Standard for Interconnecting and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces*

4.12 Anti-islanding Protection

Intentional island operation is not allowed on the EPC Distribution System.

Anti-islanding protection is required to meet the following protection requirements:

- Ensuring other Customers do not experience power quality problems;
- Preventing out-of-phase reclosing of the EPC Distribution System with the DER Facility; and
- Reducing the risk of safety hazard caused by unintentional island conditions.

EPC services both primary metered and secondary metered Customers. Anti-islanding schemes may involve upstream protection considerations such as multiple in-series devices like fuses, reclosers, and substation circuit breakers.

The following requirements are necessary to prevent the DER Facility interconnected to the EPC Distribution System from islanding:

1. The DER Facility must have anti-islanding protection. The DER Facility must have the following:
    - Under/over frequency protection as outlined in subsection 4.9 and subsection 2.4 is required and should not be compromised by the anti-islanding frequency protection settings;
    - Under/overvoltage protection as outlined in subsection 4.10 and subsection 2.2 is required and should not be compromised by the anti-islanding voltage protection;
    - DER rated in aggregate ≤500kW may utilize passive anti-islanding schemes unless otherwise dictated by EPC; and
    - DER rated in aggregate >500kW require direct transfer trip for anti-islanding protection;
2. Upon loss of one or more phases of the EPC Distribution System, the DER Facility must automatically disconnect from the EPC Distribution System within at least 1.5 seconds; and
3. The DER Provider must provide proof to EPC that the DER Facility cannot sustain an island for longer than the at least 1.5 second requirement;

4.12.1 Passive Anti-Islanding Protection

1. The DER Facility rated in aggregate <500kW applying to deliver power to the EPC Distribution System may be exempt from item requiring direct transfer trip for anti-islanding protection, but instead may be required to meet the following passive anti-islanding protection elements in replacement of direct transfer trip:
    - 81R – Rate of change of frequency; and
    - 78 – Vector Shift or 32R reverse reactive power;
2. All passive anti-islanding schemes must be submitted to EPC for review and approval;
3. The passive anti-islanding elements listed in 1) must be set as sensitive as possible to reduce the non-detection zone. These settings may be adjusted with the prior approval of EPC if they are found to cause unjustified nuisance tripping;
4. If EPC does not approve a passive anti-islanding scheme for the DER Facility rated in aggregate <500kW, direct transfer trip as outlined in subsection 4.12.2, or maximum export (32R), or MAEC may be considered;
5. The DER Provider must be aware of and accept the risk of using passive anti-islanding schemes described in item 1). EPC will not be responsible for damages incurred under these circumstances (e.g., out of phase reclosing, nuisance tripping);
6. The non-inverter DER Facility rated in aggregate <500kW must be prepared to receive a transfer trip signal from the EPC System Control Centre and cease power supply to the EPC Distribution System. Implementation of this capability may not be required for the original request for interconnection application but may be requested by EPC at any time at the DER Provider cost; and
7. An induction-based DER Facility not equipped with direct transfer trip as required in subsection 4.12.2, must ensure that the DER is not capable of self-excitation.

4.12.2 Active Anti-Islanding Protection – Direct Transfer Trip (DTT)

A DTT signal from the upstream recloser(s) or feeder breaker(s) to the DER Facility will be required for the DER Facility rated in aggregate ≥500kW requesting parallel export operation.

At EPC's sole discretion, DTT signal may not be required for an inverter-based DER Facility rated in aggregate ≥500kW and ≤5MW, meeting *UL 1741 – 3rdd Edition inclusive of Supplemental B (SB) (2021) or later editions*. For ENMAX to consider removing the DTT requirement for inverter based DERs meeting the requirements above, the DER Facility owner shall prove to ENMAX that the proposed aggregated system will meet the anti-islanding requirements with the proposed passive anti-islanding solution. The DER Facility shall undertake full scale testing as part of commissioning to ensure passive shutdown operates as planned and shall be required to verify passive anti-islanding annually in accordance with the applicable CSA standards.

A DTT signal from an EPC substation feeder breaker(s) and/or upstream recloser(s) to the DER Facility will be required under the following conditions:

- When total nameplate rating of the DER Facility and all DER connected downstream of a line recloser is >33% of the minimum feeder load or load downstream of a line recloser; and
- If the existing reclose interval of the upstream recloser(s) or feeder breaker(s) is <2.0 seconds.
- If the inverter based DER is a Grid Forming (GFM) inverter, further study and equipment (synchonizer, etc) may be required to ensure anti-islanding capability. EPC will work with the DER Provider to define requirements on a case-by-case basis.

The DER Facility must remain disconnected from the EPC Distribution System when the DTT signal is unavailable;

The DTT signal is in essence breaker status or multiple breaker status' indicating loss of supply connection to the DER site. The signal must be failsafe and upon loss of DTT communications for greater than 1 second must:

- A controlled shutdown design may be allowed upon review and approval from EPC;
- Loss of communications may activate other anti-islanding protection schemes such as directional power and overcurrent. Permissive schemes involving DTT must be submitted to EPC for review and approval; and
- The DER must remain disconnected until the DTT signal has been repaired and the EPC Control Centre has been notified that the DTT scheme is ready for operation.

In some cases, DTT is not an option due to upstream device limitations. In these cases, maximum export and directional overcurrent may be evaluated to allow for the export of power.

For any proposed DTT technologies, the DER Provider is responsible to pay for protection feasibility studies and EPC is to review and accept. Costs for any software or hardware changes, including to maintain the communications line of site, need to be paid for by the DER Provider.

Direct Transfer Trip (DTT) Requirements:

- Low latency, high reliability, high quality, communication – DTT signal and DER electrical isolation must be fully completed in less than 1.5 seconds to meet the 2.0 second automatic reclosing times (a 0.5 second margin will help ensure DER is fully disconnected from the EPC Distribution System).
- DTT to be initiated after loss of utility supply occurs or if the EPC Distribution System is in an alternate configuration other than “normal” as defined in the operating procedure.
- Fail safe communication – loss of communication will result in the DER to electrically isolate itself from the EPC Distribution System. An “OK to Generate” signal is commonly used as a method to provide a fail safe communication. If the signal is present, then the DER can export power to the EPC Distribution System; if the signal is not present then the DER must electrically isolate from the EPC Distribution System. Time delay for the DER to electrically isolate from the EPC Distribution System if “OK to Generate” signal is lost for typically 1.5 seconds.
- DER export can only be initiated when utility supply has been restored and the EPC Distribution System is configured in a “normal” state as defined by the operating procedure. In addition, verbal communication may be required between the DER facility and EPC control centers prior to the DER facility re-connecting to the EPC Distribution System.
- DTT equipment must be maintained to ensure it remains fully functional. This may require coordinated efforts between the DER facility and EPC for the purpose of scheduled maintenance and testing.
- When DTT Communication is required, the fibre/communication shall be run directly from the substation supplying the site. DTT needs to use a dedicated channel (1 fibre). The DTT can't also have SCADA on this channel. This is to ensure that DER facility’s DTT signals aren't routing through a greater fiber optic/ communications system that could be subject to outages due to maintenance which would lead to DER facility service interruptions.

4.12.3 Exceptional Interconnection Protection

Application dependent protection elements and/or schemes not listed in the Technical Requirements may be required. The EPC Distribution System, site-specific parameters or interaction of the EPC Distribution System and DER Facility may require other protection elements and schemes not listed above.

4.12.4 Protection Scheme Failures

The interconnection protection scheme design submitted by the DER Provider to EPC must include details addressing the following items:

1. The DER must be disconnected from the EPC Distribution System under the following conditions:
    - The DER Facility interconnection protection and/or protection scheme fails.
        - Protection systems provided by IED’s must have self-diagnostic features that detect and alarm on internal relay failures;
    - The interconnection or DER breaker trip coil or interrupting device fails for DERs rated in aggregated $\geq$500kW;

- DERs rated in aggregate <500kW may be included in a protection failure scheme and will be reviewed and approved by EPC on a case-by-case basis;
- The DC supply for the interconnection protection scheme is lost; and
- The DTT signal channel fails (see subsection 4.12.2).

2. Except for when the DC supply for the interconnection protection scheme is lost, disconnection must be automatic and immediate;
3. Disconnection due to DTT communication channel failure must be automatic but may be delayed as described in subsection 4.12.2;
4. DER Facility disconnect device(s) must remain open until the affected system(s) has been returned to normal and the DER Facility is ready to re-connect to the EPC Distribution System; and
5. In protection designs where self-diagnostic features do not trip the affected DER Facility's isolation devices, redundancy and/or back-up protection may be required for DERs rated in aggregate >500kW.

4.13 BREAKER FAIL

The DER Facility rated in aggregate ≥1MW must provide breaker failure protection for the primary interrupting device(s) responsible for DER disconnection. The DER Facility rated in aggregate <1MW may require breaker fail protection for the primary interrupting device(s) determined on a case-by-case basis.

Breaker fail schemes, if required, must have a maximum pickup time of 0.3 seconds; For example, if the PCC breaker fails, the protection scheme shall trip the DER isolation device(s) or any isolation device in-between. Alternatively, if the DER isolation device(s) fail, the protection scheme must trip the PCC breaker or any isolation device in between.

The DER Facility rated in aggregate <1MW will be exempt from dedicated breaker fail protection scheme(s), but instead must ensure that all DERs are disconnected from the EPC Distribution System via other isolation devices or by disabling an inverter (if applicable), or by disabling the prime mover fuel source and excitation system as appropriate.

The design of the DER Facility breaker fail scheme, if required, must be submitted to EPC for review and approval.

5.0 OPERATING REQUIREMENTS

This section describes the minimum requirements that the DER Facility connected to the EPC Distribution System must comply with when the DER Facility is in operation. Failure to comply with the specified requirements will lead to a disconnection of the DER Facility from the EPC Distribution System. An Operating Procedure between the DER Facility and the EPC Distribution System may be required as deemed necessary by EPC.

5.1 GENERAL REQUIREMENTS

1. The DER Facility must disconnect all DERs in the event there is a configuration change to the EPC Distribution System not studied or approved in the DER interconnection process;
2. All DERs must be disconnected and remain disconnected during planned and unplanned system events or as directed by the EPC System Control Centre;
3. All switching between the EPC Distribution System and the DER Facility involving the manual operation of an air break switch will require the prior disconnection of any interconnected DER from the EPC Distribution System. This switching will be directed by the EPC System Control Centre; and
4. Power exports into the Network System or the secondary voltage services of high-density systems are not allowed. For more information on secondary network interconnections, refer to section 10.0.

5.2 RECONNECTION OF DER FOLLOWING AN OUTAGE OR SHUTDOWN

The DER reconnection to EPC Distribution System power supply will be allowed by EPC under the following circumstances:

1. The DER Facility with generation offline may manually reconnect to a distribution feeder within 300 seconds using the DER Provider-owned reclosers, provided that the following conditions are met:
    - The distribution feeder has successfully re-energized by the original feeder source and the distribution voltages and system frequency are within normal voltage operating limits for a constant period of the Duration required before a DER can Enter Service (see 3.4.3) ;
    - The fault is not downstream of the PCC; and
    - An EPC Distribution System auto-recloser has not activated after a DER protection, or DTT scheme has not tripped the facility;
2. Automatic DER reconnection will be allowed under the following conditions:
    - The distribution feeder has successfully re-energized by the original feeder source and other distribution voltages are within normal voltage operating limits for a constant period of the Duration required before a DER can Enter Service (see 3.4.3);
    - The fault is not downstream of the PCC;
    - Automatic DER reconnection is only permitted if the DER's isolation device has communication and telemetry established with EPC's protection equipment[14];

[14] The EPC protection equipment is typically EPC's feeder breaker or distribution automation switch.

- EPC Distribution System voltage is stabilized and within the normal voltage and frequency operating limits described in subsection 2.2 and subsection 2.4;
- The DER may be required to adjust reconnection delay based on findings from the interconnection process or any subsequent studies; and
- If feeder restoration is not restored to normal feeder configuration within 15 minutes, the DER automatic reconnection must be disabled; and

3. Permission from the EPC System Control Center is required for the following reconnection:
    - The DER Facility with a rotating machine ≥ 500kW must call the EPC System Control Center operations before reconnection after a sustained disturbance to feeder (>15 minutes); and
    - Special design and operation considerations are required for DERs rated in aggregate >500kW that is connected to feeders with distribution automation. Sequencing and reconnection capability will be reviewed and approved by EPC on a case-by-case basis.

5.3 SINGLE CONNECTION PATH

The DER Facility may only require one connection path, with no alternate connection paths. The connection path will be studied and clearly identified as part of the DER Facility's SIA and Operating Procedures. In this case, the DER Facility must comply with the following requirements:

- The DER Facility connection to the EPC Distribution System must be restricted to the "normal EPC Distribution System supply configuration" of the connection path;
- If the EPC Distribution System supply configuration of the connection path is abnormal, the DER Facility must be disconnected and remain disconnected, until the normal configuration is restored;
- The DER Provider may request an additional connection path, subject to review and approval by EPC, and additional SIAs will be required as a result; and
- In the event an alternate connection path is approved, the SIA, Operating Procedures and Interconnection Agreement will be revised to include the approved alternate connection path.

5.4 ISLANDING: INTERCONNECTED

Intentional or unintentional islanding is not permitted within the EPC Distribution System. During an unintentional islanding event, the DER Facility must detect the island condition and cease to energize the EPC Distribution System within 1.5 seconds.

Islanding detection and protection requirements must be met. For further information on islanding refer to subsection 4.12.

5.5 AGGREGATIONS OF DER FROM SEPARATE DER FACILITIES

DER Providers that intend to operate multiple DERs located in different DER facilities as a single aggregated DER, or virtual power plant(VPP), may have additional requirements from EPC. These additional requirements may include, but are not limited to, real time operational data including aggregate active and reactive power production as per Class 3 in 6.3, aggregate remote trip and/or curtailment capability when sent from EPC, as well as additional studies and mitigations for the aggregate impacts of the proposed DER sites operation. All proposed aggregation requires EPC review and acceptance prior to proceeding.

6.0 SCADA SYSTEMS & COMMUNICATIONS

6.1 OVERVIEW

SCADA is a computing, communications, and visualization architecture used to monitor and control individual pieces of equipment as a system to ensure the system is working properly as a whole regardless of ownership and demarcation. SCADA architecture is based on a master and outstation scheme where the master device will request information or send commands to the outstation device, and the outstation device responds. Additionally, an outstation device can provide data as values change on the system.

The DER owner may have the need to monitor more points and individual DER locations than required by this document for their own needs. Where DER or aggregate DER is greater than 250 kVA a single point of DER aggregation for data collection may be used or each individual DER may be monitored.

This section describes the minimum requirements to allow for communications between the EPC and DER Facility SCADA systems.

6.2 EQUIPMENT & INFRASTRUCTURE

The EPC Distribution System and DER Facility SCADA systems must communicate using the distributed network protocol (DNP)3 protocol *IEEE Std 1815-2012 - IEEE Standard for Electric Power Systems Communications-Distributed Network Protocol (DNP3)*. The DNP3 master device on the EPC Distribution System SCADA system will poll a single IED such as a remote terminal unit (RTU), gateway, or front-end processor on a DER Provider's SCADA system.

The DER Provider must provide all required hardware and software to complete the telecommunications infrastructure up to the Telecommunication Demarcation Point. In cases where the infrastructure is provided as a service by a third-party, the DER Provider will be responsible to lease, rent, or otherwise procure this service up to the Telecommunication Demarcation Point.

The physical demarcation between the EPC Distributions System SCADA system and the DER Provider's SCADA system must be mutually agreed upon to ensure both EPC and the DER Provider have access to the respective party's SCADA telecommunication equipment.

6.2.1 SCADA Diagrams and Functional Specifications

The DER Provider must provide a SCADA block diagram and functional specifications to EPC for review and approval. This block diagram must provide high-level details on the SCADA devices that will be involved and must also highlight the proposed communication architecture that will be used between the EPC Distribution System and the DER Facility equipment. At a minimum, this block diagram must include the following:

- The EPC SCADA master device;
- The DER Facility DNP3 outstation device;
- The communications medium and any media conversion; and
- Any communication redundancy schemes.

Once the documentation above has been provided by the DER Provider, EPC will review the documentation and develop a SCADA commissioning procedure.

6.3 DATA EXCHANGE

The minimum requirements for telemetry varies depending on the aggregate rated power output of DER or multiple DER within the same DER facility involved. The three classes of telemetry requirements based on the aggregate rated power output of generation in the DER Facility are listed in Table 10.

Table 10: Generation Classes for Data Acquisition and Telemetry

Class	Definition
1	0kW < Gen < 150kW
2	150kW =< Gen < 500kW
3	500kW =< Gen

In situations where the generation is part of transfer trip or remedial action schemes, additional points may be required and will be reviewed and approved by EPC on a case-by-case basis.

6.3.1 Point Lists

The DER Provider must provide a DNP3 point list for EPC's review and approval. Once the point list has been reviewed and found to meet the minimum requirements it will be finalized and accepted by EPC. Additional points may be required to be provided by the DER Provider in finalizing the point list. This list will be used as the basis for commissioning, testing, and any other documentation of the DER Facility SCADA system. At a minimum, this point list is required to include the following:

- DNP3 type;
- DNP3 variation;
- Point Number;
- Point Name;
- Unit for analog points; and
- Scaling factor for analog points.

The telemetry requirements and minimum point requirements for each generation class are listed in Table 11. These requirements are to be provided in aggregate for all DER in the DER Facility. As required, ENMAX Power can specify additional point requirements.

Table 11: Telemetry Requirements for DER

<table>
<tr><th>Class</th><th>Signal Type</th><th colspan="2">Point Description</th><th colspan="2">Parameter</th><th>Accuracy Level</th><th>Resolution</th></tr>
<tr><td>1</td><td colspan="7">No status or analog points are required to be reported over SCADA</td></tr>
<tr><td rowspan="2">2 [1]</td><td>Digital</td><td colspan="2">Status of the disconnect device at the POC</td><td>0 = Open</td><td>1 = Closed</td><td colspan="2" rowspan="5">N/A</td></tr>
<tr><td>Analogue</td><td colspan="2">No analogue points are required</td><td colspan="2">N/A</td></tr>
<tr><td rowspan="17">3 [3]</td><td rowspan="3">Digital</td><td colspan="2">Status of the disconnect device at the PCC</td><td rowspan="3">0 = Open</td><td rowspan="3">1 = Closed</td></tr>
<tr><td colspan="2">Status of the generation interconnection breakers</td></tr>
<tr><td colspan="2">Status of switching devices which are part of a protection and control scheme</td></tr>
<tr><td rowspan="14">Analogue</td><td rowspan="7">At PCC [2]</td><td>Real power</td><td>kW</td><td rowspan="2">+: power flows out of site / -: power flows into site</td><td rowspan="14">Measuring elements - measurement accuracy requirements specified in Appendix 4 Minimum requirements for Manufacturers Stated Measurement Accuracy, or better; end-to-end requirement - +/- 2% or better of full scaler</td><td rowspan="14">0.5% or better of the point being monitored</td></tr>
<tr><td>Reactive power</td><td>KVar</td></tr>
<tr><td>All phase-to-neutral voltages (RMS)</td><td>V</td><td></td></tr>
<tr><td>Neutral-to-earth voltage (RMS)</td><td>V</td><td></td></tr>
<tr><td>All phase currents (RMS)</td><td>A</td><td></td></tr>
<tr><td>Neutral current (RMS)</td><td>A</td><td></td></tr>
<tr><td>Frequency</td><td>Hz</td><td></td></tr>
<tr><td rowspan="7">At POC [2]</td><td>Real power</td><td>kW</td><td rowspan="2">+: power flows out / -: power flows in</td></tr>
<tr><td>Reactive power</td><td>KVar</td></tr>
<tr><td>All phase-to-neutral voltages (RMS)</td><td>V</td><td></td></tr>
<tr><td>Neutral-to-earth voltage (RMS)</td><td>V</td><td></td></tr>
<tr><td>All phase currents (RMS)</td><td>A</td><td></td></tr>
<tr><td>Neutral current (RMS)</td><td>A</td><td></td></tr>
<tr><td>Frequency</td><td>Hz</td><td></td></tr>
</table>

Notes:

1. In case where the generation is to install SCADA communication with EPC for a transfer trip scheme and/or remedial action scheme, the telemetry requirements of Class 2 are the same as Class 3.
2. For the identification of PCC and POC, refer to Appendix 2

3. The generation equal to or larger than 5MW rated capacity shall provide separate data points to AESO to meet the SCADA requirements of AESO (refer to AESO website for the SCADA requirements)
4. 'End-to-end' accuracy means that the discrepancy between the measurements at the field CT/PT and the retrieved values from ENMAX SCADA system should not be more than the acceptable threshold

6.3.2 DER Information Exchange: Management Information

As per IEEE 1547 section 10.6, DER facility to have provisions for the read and write information exchange of the operating modes as well as the set points for the operating modes that the DER facility are permitted to operate in. This requirement will be evaluated and determined for DER sites during the interconnection process.

6.3.3 Polling

Polling refers to a type of data that is requested and how often it is reported. There are two methods of Polling that are accepted by EPC: Periodic Polling and Report by Exception.

1. Periodic Polling

   Periodic polling, referred to as integrity polls in DNP3, requests all data for all points as well as any changes on a predefined schedule. The minimum polling rate for integrity polls for periodic polls will be 4 seconds.

2. Report by Exception

   Report by Exception is an event-based reporting scheme. It looks for significant changes in analog values or any status point change.

In DNP3, this event-based data is referred to as class data. For Report by Exception Polling, the minimum polling rates for DNP3 class data is 2 seconds and the minimum polling rate for Integrity Polls is 5 minutes.

6.3.4 Deadbands

Deadbands are used to determine when an analog value has changed enough that it should create a DNP3 event to be sent as class data. Table 12 lists the minimum deadband requirements for SCADA.

Table 12: Minimum Deadband Requirements for SCADA

Quality	Type	Deadband
Voltage	Secondary	1V
	Primary	100V
Current	Secondary	100A
	Primary	10A
Power	Real Power	100kW
	Reactive Power	50kVar
Frequency	All	0.1Hz

A smaller deadband value may be required in cases where the minimum specified deadband values are a significant percentage of the total expected value.

6.3.5 Time & Time Stamping

Time stamping is required for Generation Classes 2 and 3 with transfer trip. Time will be determined using a global positioning system (GPS) clock. The GPS clock base time will be Coordinated Universal Time (UTC). The GPS clock will adjust between daylight savings time and standard time automatically. The GPS clock will have one millisecond timestamping accuracy. All GPS Clocks will use *IRIG Standard 200-04 – IRIG Serial Time Code Formats*, *IRIG-B Format B004*, and *IEEE Std 1344-1995 IEEE Standard for Synchrophasors for Power Systems* which includes the year value extension. Details of time synchronizing the DER Facility's IED devices to the GPS clock will be mutually agreed upon between EPC and the DER Provider during the DER interconnection process.

7.0 TELECOMMUNICATION INFRASTRUCTURE REQUIREMENTS

This section describes the telecommunication requirements for protection and control schemes that require telecommunications. It also describes the telecommunication requirements between the DER Facility and EPC Distribution System SCADA systems.

7.1 GENERAL REQUIREMENTS

EPC requires telecommunication infrastructure for the DER Facility rated in aggregate >150kW interconnected with the EPC Distribution System to enable the communications of data: for protection, real time operation, and monitoring. Some telecommunication infrastructure will be integrated into the SCADA equipment while others will be standalone. The telecommunication requirements take into consideration all equipment used in the SCADA system.

All telecommunication infrastructure between the EPC Distribution System and the DER Facility SCADA system will be reviewed and approved by EPC on a case-by-case basis. This will ensure that both parties have the required access to equipment for the purpose of updates, maintenance, and repairs.

The telecommunication infrastructure will support fast, secure, and reliable communication to meet the technical requirements for the protection, control, and monitoring requirements of the DER Facility.

Several types of telecommunication infrastructure are available, however, not all are appropriate for each type of DER Facility. Each DER will be reviewed and approved for interconnection by EPC based on the telecommunication requirements of the DER Facility.

If a DER Provider is considering wireless telecommunications there will be additional requirements to be met. Please contact ENMAX Power for further information on the additional information, technologies and protocols required. Note that web-based technologies are not accepted to meet SCADA requirements.

AESO has additional requirements for DER greater than 5MW in aggregate. See AESO’s ISO Rule 502.8 for further information.

7.1.1 Telecommunication Facilities for Teleprotection

Teleprotection has strict reliability and latency requirements for telecommunication and the supporting telecommunication infrastructure.

Teleprotection is used to help protect the EPC distribution system as well as the DER Facility by providing critical two-way information between the EPC Distribution System and the DER Facility.

Teleprotection and Direct Transfer Trip requirements described in section 4.0 must be met by the proposed telecommunication infrastructure. If these requirements are not met and/or telecommunications fail, the DER will be tripped off.

7.1.2 Telecommunications for Real Time Control & Monitoring

Real time control and monitoring is used to remotely monitor the analog values such as power and current. It is also used to monitor whether a disconnection device is open or closed. Additionally, real time control and monitoring can provide remote control capability such as opening or closing a disconnect device.

7.1.3 Reliability Requirements

Minimum reliability requirements are based on the functions the telecommunication infrastructure is designed to support. Reliability statistics will be generated to measure performance of the entire communications infrastructure from the DER Facility monitoring equipment to the Telecommunication Demarcation Point with the EPC Distribution System telecommunication infrastructure.

7.1.3.1 Teleprotection

A telecommunication failure is any situation where the requirements described in section 6.0, are not met due to a failure of the telecommunication infrastructure. In the case of a telecommunication failure in a teleprotection scheme, the DER will be tripped and will remain tripped until the telecommunications failure has been resolved.

DER Facility telecommunication infrastructure must meet the following minimum requirements:

- Annual average availability of 99.7% (translating to approximately one day of downtime per year);
- Mean Time to Repair (MTTR) of 24 hours; and
- Mean Time Between Failures (MTBF) of one year.

7.1.3.2 Real Time Control and Monitoring

The following requirements must be met for real time monitoring equipment:

- MTTR of seven days; and
- MTBF of two years.

If the DER Facility is used as part of a remedial action scheme, special protection scheme, or automated dispatch, the MTTR for telecommunications must be 24 hours.

Additionally, if the failure rates or repair time performance falls below a certain threshold, the DER Provider may be asked to disconnect the DER until the telecommunication performance is improved. Those minimum thresholds for failure rates or repair time performance are specified as follow:

1. MTBF < one year; and
2. MTTR > 24 hours.

Note: Measurement of the MTTR will start when the telecommunication failure began, not when it was discovered.

8.0 METERING REQUIREMENTS

Metering requirements will vary with the type and intent of the DER Facility. For more information refer to the *ENMAX Metering Standard* for all metering requirements.

EPC reserves the right to request an inspection and the DER Provider must grant access and allow the DER Facility to be inspected by ENMAX Revenue Metering to ensure compliance with EPC metering requirements. EPC will provide the DER Provider a list of all inspection requirements prior to project initiation.

9.0 REPORTING REQUIREMENTS

9.1 OVERVIEW

The DER Facility rated in aggregate ≥5,000 kW interconnected with the EPC Distribution System must record the data specified below. The DER Provider must keep the recorded data for a minimum period of two weeks and provide it within five working days of an EPC request. These reports will be used by EPC to conduct technical reviews including load/generation profile surveys and disturbance analysis. Data for reporting requirements is recorded at the PCC, unless otherwise directed by EPC during the DER interconnection process.

Please note that AESO may have additional requirements for units rated in aggregate ≥5,000 kW.

9.2 POWER QUALITY REPORTING

The DER Facility subject to Reporting Requirements must install a Power Quality Recorder (PQR) at the PCC. The installed power quality instrument must be compatible with *IEC Standard 61000-4-30 Class A - Power quality monitor: Development and performance analysis* and must be previously approved by EPC. The PQR must provide comprehensive information on all power quality parameters (e.g., voltage, current, harmonic, transient and voltage unbalance). The PQR must also perform the following functions:

- Record voltage and current at minimum 256 samples/cycle;
- Trigger voltage and current waveforms, simultaneously on all channels, when any phase voltage is below 0.95pu or above 1.10pu of its nominal value;
- Provide 4 pre-fault and 2 post-fault waveform values;
- If the DER Facility is connected to a medium voltage system, a scaling factor must be applied to all power quality measurements to reflect the real values;
- Record millisecond impulsive and low to medium frequency oscillatory transients as per *IEEE Std 1159-2009 IEEE Recommended Practice for Monitoring Electric Power Quality -Section 4*;
- Report Pst and Plt values based on *CAN/CSA-IEC 61000-4-15 Electromagnetic Compatibility (EMC) - Part 4: Testing and Measurement Techniques - Section 6: Immunity to Conducted Disturbances, Induced by Radio-Frequency Fields* -measurement techniques section;
- Record voltage unbalance as defined in subsection 3.3.; and
- Recorded data must be provided to EPC in COMTRADE or PQDIF file format.

10.0 SECONDARY NETWORK INTERCONNECTIONS

A secondary network is a complex power system with a web of multiple parallel sources of power to each customer. The benefit for Customers connected to these systems is that they should rarely experience interruptions in power delivery. The nature of the Network System does not allow Customers to export power to the network due to safety and technical reasons.

Within the City of Calgary, EPC has several geographic areas which are supplied by secondary networks in addition to the areas described in Figure 1. Refer to the Network boundary maps or enmax.com for more information For further information on interconnecting DERs within the EPC secondary networks, please refer to the Generation section of the Network Servicing Policies and guidelines..

The same network equipment that cannot accept exporting DER is also used by EPC in high-density systems to supply power to a few large developments outside of the downtown core. Please consult EPC for details on proposed DER installations in high density areas as the similar interconnection restrictions as in the network apply.

11.0 TESTING & COMMISSIONING

This section describes the minimum testing and commissioning requirements for the DER Facility interconnecting with the EPC Distribution System. The scope of this section covers testing for the interface equipment between the DER Facility and the EPC Distribution System.

11.1 GENERAL REQUIREMENTS

The DER Provider is responsible for ensuring that the DER Facility complies with the testing requirements specified in this section. EPC reserves the right to require additional testing if deemed necessary for the DER Facility interconnection with the EPC Distribution System.

The DER Facility's testing must meet the requirements of the following standards:

- *IEEE Std 1547 (2018) - IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces*, Section 11 - Interconnection Test Specifications and Requirements;
- *IEEE Std 1547.1 (2020) - IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems;*
- *CAN/CSA 22.3 No.9 (2020) Interconnection of distributed resources and electricity supply systems - Section 8 Interconnection Tests; and*
- *UL 1741 – 3rdd Edition inclusive of Supplemental B (SB) (2021)* or later editions as required by EPC*. – Advanced Inverter Testing addition to Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources.*

Additionally, DER Facility's which have Battery Energy Storage Systems must meet the testing requirements of the following standards for respective Energy Storage equipment:

- UL1973 (2022) Standard for Batteries for Use in Stationary, Vehicle Auxiliary Power and Light Electric Rail (LER) Applications
- UL9540 (2025) - Energy Storage Systems and Equipment
- UL9540a (2025)- Test Method for Battery Energy Storage Systems (BESS)
- NFPA 855 (2026) - Standard for the Installation of Stationary Energy Storage System**s** (2026)

The DER Provider must provide EPC with the specifications and a list of standards of the DER Facility interconnection equipment. The DER Provider will also compile and provide a testing plan for the DER Facility interconnection system to EPC for review and approval. The timing of the submission of the testing plan will be determined as part of the DER interconnection process. EPC will provide the DER Provider with comments and any requests for changes to the DER Facility's interconnection system in a timely manner. The DER Provider must address and respond to the EPC comments in writing and make the requested changes in a mutually agreed-upon time.

The DER Provider must notify EPC in writing at least two weeks before energization and start-up testing of the DER Facility's DER. Additionally, EPC reserves the right to witness the testing of any equipment and protection systems associated with the DER Facility's interconnection.

11.2 TESTING

The following describes the three categories of DER Facility interconnection system testing:

1. Type Testing;
2. Production Testing; and
3. Verification/ Acceptance Testing.

11.2.1 Type Testing

Type tests are conducted by an independent testing laboratory on a sample of the DER Facility equipment to prove that the equipment complies with the standards listed in the equipment specifications. The manufacturer of the equipment must be able to provide a certified type test for every standard listed in the equipment specification data sheet. EPC reserves the right to request a copy of the DER Facility interconnection equipment type tests concurrently with of the DER Provider submitting the DER Interconnection application and/or for any equipment added to or modified at the DER Facility interconnection system thereafter. EPC may require additional type tests to confirm that the DER Facility interconnection equipment complies with the applicable standards required for the DER Facility interconnection with the EPC Distribution System.

The minimum type tests requirements must include the following:

- Temperature stability;
- Response to abnormal frequency;
- Response to abnormal voltage;
- Synchronization or Entering Service;
- Interconnection integrity;
- Surge Withstand;
- Islanding;
- Open-phase;
- Reconnect following abnormal condition disconnect;
- DC Injection (for inverters without interconnection transformers);
- Harmonics;
- Voltage and power control requirements;
- Flicker;
- Loss of control circuit power;
- AC output short circuit contribution tests; and
- Circuit unbalance test.

11.2.2 Production Testing

Production tests are conducted at the equipment manufacturer facilities on every unit included in a DER Facility interconnection system. The production tests must confirm that the manufactured units configured with default settings are aligned with the equipment specification and performance requirements.

The minimum production test requirements must include the following:

- Response to abnormal frequency;
- Response to abnormal voltage; and
- Synchronization or Entering Service.

11.2.3 Design Evaluation

When requested by ENMAX Power, the DER Provider shall provide EPC the 'design evaluation' related documentation as per IEEE 1547.1 (2020) which outlines how the DER Provider's facility's design has incorporated all the interconnection requirements outlined by ENMAX Power.

11.2.4 Verification / Acceptance Testing

Verification and acceptance testing will be conducted after the DER Facility interconnection system is installed and is ready for operation. The verification and acceptance test will be conducted in coordination with EPC.

The testing must be conducted in accordance with the testing plan submitted to and accepted by EPC during the design stage. EPC reserves the right to witness and as necessary conduct any or all the tests associated with the DER Facility interconnection system.

The DER Provider must notify EPC in writing at least two weeks prior to the start of verification and acceptance testing.

For sites greater than 1000kVA in aggregate, or smaller sites as required by ENMAX Power, DER Providers are to hire a third party to conduct the IEEE Conformity Assessment Program (ICAP) in accordance with IEEE 1547-2018 and IEEE 1547.1-2021 prior to design completion.

11.2.4.1 Interconnection verification and inspection

The testing plan, verification and evaluation tests must include the following:

- Measurement location;
- Measurement accuracy;
- DER Facility interconnection capability;
- DER Facility reactive power capability;
- DER Facility voltage and power control capability;
- Presence of a means of disconnecting the DER Facility from the EPC Distribution System;
- Verification of the interconnection transformer winding;
- Verification of the transformer neutral impedance grounding;
- Verification of the grounding coordination;
- For a three-phase system, verification of the phasing and phased rotation of the EPC Distribution System and the DER Facility;
- Verification of the interrupting device capability;
- Verification of the device rating;

- Verification of the final DER Facility interconnection system protection settings;
- Verification of the anti-islanding functionality;
- Verification of the synchronization and Entering Service criteria;
- Verification of the instrument transformers parameters in accordance with the design;
- Testing of the overall system including the protective relays, circuit breakers and telecommunications including DTT (If applicable);
- Load testing of the protective relays;
- Verification of the DER Facility disconnection following loss of power supply, failure of protection system and/or breaker failure;
- Verification of a fail-safe DTT trip on loss of communication signal;
- Verification that power and control wiring comply with drawings and manufacturer requirements;
- Verification of compliance with the applicable Electromagnetic Compatibility (EMC) standards;
- Verification of compliance with the applicable Surge Withstand Capability (SWC) standards; and
- Verification of the energization cessation under the following conditions:
  - Abnormal frequency;
  - Abnormal voltage;
  - Protection system failure; and
  - Reverse Power or minimum-power limitations.

Additionally, the following verifications and inspections will take place, at the sole discretion of EPC:

- The DER Facility does not cause objectionable harmonic or voltage distortion;
- The DER Facility does not cause objectionable voltage flicker;
- The DER Facility does not cause objectionable voltage unbalance; and
- The DER Facility must limit the injection of DC current into the EPC Distribution System.

11.2.4.2 Lock out and tag out during construction

Where determined necessary by EPC, the DER Provider will allow and support ENMAX Power to lock out and tag out the DER facilities DER isolation device, interconnection breaker, or other required locations with an EPC lock.

11.2.4.3 Providing DER settings as Common file format for DER exchange

DER Providers are to program DER settings as outlined in these Technical Requirements and/or required through the EPC interconnection process and show proof by submitting the settings as a settings file using the *EPRI Common File Format for DER Settings Exchange and Storage* (Version 2.0) Applied Settings template (see Appendix 6) back to ENMAX Power for acceptance prior to energization.

Additionally, as required, EPC will communicate specific Specified Settings for a DER Provider to implement through the format shown in Appendix 5 which shows a typical example of the Specified Settings using the *EPRI Common File Format for DER Settings Exchange and Storage* (Version 2.0).

11.3 SCADA COMMISSIONING

SCADA commissioning falls into the following two categories:

1. The new DER Facility that does not have any previous SCADA systems in place; and
2. The existing DER Facility where new DERs are being added or changes to the data or equipment are to take place.

SCADA commissioning is required in both cases.

The scope of SCADA commissioning includes verification and agreement between EPC and the DER Provider of the correct operation, functionality and programming of the DER Facility's SCADA equipment. The scope will also include testing the telecommunication link between the EPC Control Centre and a DER Facility's Communication Processor/Gateway, the communication links between the Communication Processor/Gateway and RTU/ Remote I/O (Input/Output), Annunciators, and Relays/IEDs. The mappings and settings of the Communication Processor/Gateway and relays/IEDs will also be verified during the SCADA commissioning.

EPC will develop and provide the DER Provider with a SCADA commissioning procedure once the documentation described in subsection 6.2.1, has been provided by the DER Provider and reviewed and approved by EPC.

EPC reserves the right to witness SCADA commissioning tests. To ensure that the commissioning tests comply with the applicable standards and are performed correctly, EPC may witness the tests and receive written certification of the results.

11.4 HARDWARE OR SOFTWARE CHANGES

Whenever interconnection system hardware or software is changed there can be an effect on the equipment and functions listed below.

1. Re-commissioning of equipment is required for all hardware changes impacting the interconnection listed as follows:
    - Switchgear and conductors;
    - Protective relays;
    - RTU's and sensors; and
    - Communication devices;
2. A re-test shall be required of all potentially affected functions including but not limited to the following:
    - Overvoltage and undervoltage;
    - Overfrequency and underfrequency;
    - Fault Detection;
    - Inability to energize a de-energized line;
    - Time-delay restart after EPC Distribution System outage;
    - Reverse or minimum power function (if applicable);
    - Synchronizing controls (if applicable); and
    - Anti-islanding functions (if applicable).

11.5 SWITCHGEAR & METERING

EPC reserves the right to witness the testing of installed switchgear and metering. The DER Provider must notify EPC in writing at least 10 days prior to any testing.

11.6 MARKING & TAGGING

Marking, tagging and other signage requirements will vary with the type and intent of the DER Facility. These requirements are listed within the DER section of the *ENMAX Metering Standard*.

11.7 COMMISSIONING & INSPECTION

EPC reserves the right to request and the DER Provider must allow the EPC to witness the construction and commissioning or any part of work related to the equipment being commissioned including inspection of materials, detailed drawings, documents (e.g., test plans, test logs), manufacturing operations and installation procedures, and to witness tests and evaluate results of the commissioning tests.

11.8 MAINTENANCE

The DER Provider must maintain a quality control and inspection program using *CSA Z463-18 (2018) Maintenance of Electrical Systems* as a guide. Inspections must occur at least monthly. EPC reserves the right to request at any time an auditable log of these required inspections. All DER Facility equipment, up to and including the visible point of isolation, is the responsibility of the DER Provider. The DER Provider is responsible for maintaining the equipment to accepted industry standards, but specifically the *Canadian Electrical Code (CEC) Part 1, paragraph 2-300*.

The DER Provider is fully responsible for routine maintenance of the DER Facility control and protective equipment and the keeping records of that maintenance.

EPC reserves the right to request and the DER Provider must provide a copy of the planned maintenance procedures and a maintenance schedule for the DER Facility interconnection protection equipment.

12.0 APPENDICES

APPENDIX 1

DEFINITIONS

Term	Definition
active power	Active or real power to do actual work on a load. Active power is measured in *watts (W)* and is the power consumed by electrical resistance.
AESO	The Independent System Operator established in the *EUA* to carry out the duties of the Independent System Operator under the *EUA* and carrying on business as the Alberta Electric System Operator. Refer to website: www.aeso.ca
AEUC	Alberta Electrical and Communication Utility Code. Refer to website: www.safetycodes.ab.ca
anti-islanding	A protection system aimed at detecting islanded conditions (see island) and disconnecting the DER Facility from the distribution system if an island forms.
AIES	The Interconnected Electric System which is all transmission facilities and all electric distribution systems in Alberta that are interconnected but does not include an electric distribution system or a transmission facility within the service area of the City of Medicine Hat or a subsidiary of the City of Medicine Hat, unless the City of Medicine Hat passes a bylaw that is approved by the Lieutenant Governor in Council under Section 138 of the EUA.
APEGA	Association of Professional Engineers and Geoscientists of Alberta. Refer to website: www.apega.ca
apparent power	The power supplied to the electric circuit – typical from a power supplier to the grid - to cover the real and reactive power consumption in the load. Apparent power is measured in volt-amperes (VA) - the AC system voltage multiplied with flowing current.
AUC	Alberta Utilities Commission. Refer to website: www.auc.ab.ca
automatic circuit recloser	An overcurrent protection device that is used by EPC to detect faults on distribution system feeders and that has the ability to open and reclose after a specified time, allowing momentary faults to clear.
Battery Energy Storage System (BESS)	Battery Energy Storage Systems are inverter based distributed energy resources that can store energy in a battery technology and then produce that energy as active and reactive power at a later time.
Bulk Electric System (BES)	As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.

CEA	Canadian Electrical Association. Refer to website: www.electricity.ca
CEC	The Canadian Standards Association's C22.1 Safety Standard for Electrical Installations Part 1, also known as the Canadian Electrical Code.
clearing time	The time from the start of the abnormal condition to when the DER ceases to energize the distribution system.
closed transition	A mode of operation in which the DER is operated in parallel with the EPC Distribution System for a brief period of time, to ensure that the load is maintained while transferring from the utility to the DER or vice versa.
connected load	In relation to a DER Facility, the sum of the capacities or ratings of the energy consuming apparatus connected to the EPC Distribution System at the DER Facility.
CSA	Canadian Standards Association. Refer to website: www.csa.ca
current	The flow of electricity in a conductor. Current is measured in amperes. Current includes: <u>Alternating Current (AC)</u> An electric current that reverses direction at regularly recurring time intervals and has alternating positive and negative values. In North America, the standard for alternating current is 60 complete cycles each second. Such electricity is said to have a frequency of 60 Hz. <u>Direct Current (DC)</u> A unidirectional electric current in which the changes in value are either zero or so small that they may be neglected. The current supplied from a battery is direct current.
Customer	A Person purchasing electricity for the Person's own use, a DER Provider, or a Developer, as context requires.
demand	The rate at which energy is delivered to or by a system (expressed in kVA) at a given instant or average over any designated period of time.
disconnection device	A device or group of devices that allows the conductors of a circuit to be disconnected from their source of supply. These devices include circuit breakers, isolation devices, interruption devices.
distributed energy resource (DER)	A source of electric power that that is not directly connected to a bulk electric system, which includes distributed connected generation and energy storage technologies.

DER Facility	All equipment including DERs, interconnection systems, transformers, protection & coordination systems, sensing devices on the DER Provider's side of the point of common coupling.
DER Provider	A Person who owns, operates or is otherwise responsible for a DER Facility that is interconnected to the EPC Distribution System for the purpose of generating electric power.
DNP3	Distributed Network Protocol. An OSI 3 Layer Enhanced Performance Architecture protocol standard for telecontrol applications. Refer to website: www.dnp.org
distribution connected generation	Electric generation facilities that are connected to a distribution system through a point of common coupling. Distribution connected generation includes micro-generation and distributed generation technologies.
distribution system	The plant, works, equipment, systems and services necessary to distribute electricity in a service area that operates at a nominal voltage of 25,000 V or lower and that allows electrical power to be delivered to a load and DER facilities. Also referred to as a Grid.
EMC	Electromagnetic Compatibility. Refer to website: https://ec.europa.eu/growth/single-market/european-standards/harmonised-standards/electromagnetic-compatibility_en
energize	The connection of metering or electrical equipment to the EPC Distribution System to permit energy to flow to the DER Facility and includes any derivation of this word, as the context requires.
energy	The capability of electricity to do work, measured in kilowatt hours.
energy storage	Technology to store electrical energy so it can be available to meet demand whenever needed.
EN, ENV	European Standard, European Pre-Standard. Refer to website: www.en-standard.eu
enter service	Begin operation of the DER with an energized distribution system.
EPC	ENMAX Power Corporation and includes a Person, if any, authorized to act on its behalf under the EUA.
EPC Distribution System	The plant, works, equipment, systems and services necessary to distribute electricity in the EPC service area but does not include a generating unit or a transmission facility.
EPC System Control Centre	EPC function responsible for dispatching load and generation on the EPC Distribution System, in real time.
EPC Ts&Cs	EPC Distribution Tariff - Terms and Conditions

EUA	The *Electric Utilities* Act (Alberta)
export	Injecting power into the distribution system through the PCC from a DER facility.
Facilities	EPC's physical facilities including, without limitation, transmission and distribution lines, wires, transformers, meters, meter reading devices, load limiting devices and other electrical apparatus.
fault	An event occurring on an electric system such as a short circuit, a broken wire, or an intermittent connection.
FERC	Federal Energy Regulatory Commission. Refer to website: www.ferc.gov
ferroresonance	An oscillatory phenomenon caused by the interaction of system capacitance with the non-linear inductance of a transformer, usually resulting in a high transient or sustained overvoltage.
flicker	The subjective impression of fluctuating luminance caused by voltage fluctuations.
generator	An electromechanical device that converts mechanical energy into electrical energy.
GPS	Global Positioning System
harmonics	Sinusoidal currents and voltages with frequencies that are integral multiples of the fundamental power line frequency.
IEC	International Electrotechnical Commission. Refer to website: https://www.iec.ch/
IEEE	Institute of Electrical and Electronics Engineers, Inc. Refer to website: www.ieee.org
induction generation	An induction machine that is driven above its synchronous or zero-slip speed by an external source of mechanical power in order to produce electric power. It does not have a separate excitation system and therefore requires its output terminals to be energized with alternating-current voltage and supplied with reactive power to develop the magnetic flux.
intelligent electronic device (IED)	A device that performs electrical protection functions, advanced local control intelligence, has the ability to monitor processes and can communicate directly to a SCADA system.
interconnection	The result of the process of electrically connecting a DER system in parallel to a distribution system.
Interconnection Agreement	An agreement between EPC and a DER Provider, which sets the terms upon which EPC provides Distributed Generation Interconnection Services to the DER Provider and the associated Rate Schedule and Fee Schedule.
interconnection system	The collection of all equipment and functions, taken as a group, used to interconnect a DER unit to a distribution system.

interrupting device	A device capable of being opened and reclosed whose purpose is to interrupt faults and restore service or disconnect loads. These devices can be manual, automatic, or motor-operated. Examples include circuit breakers, motor-operated switches, and electronic switches.
inverter	A machine, device, or system that changes direct-current power to alternating-current power.
island	a) The portion of the distribution system that is energized by one or more DERs through their PCC(s) while that portion is separated electronically from the rest of the distribution system; or b) The condition in which a portion of the distribution system is energized by one or more DERs through their PCCs while that portion is separated electrically from the rest of the distribution system. Intentional – a planned island. Unintentional – an unplanned island.
load	The demand and energy delivered or required to be delivered to a DER Facility.
Maximum Allowable Export Capability (MAEC)	The maximum allowable export that a generator is permitted to export to the grid.
Mean Time Between Failures (MTBF)	The sum of the time between two or more failures divided by the number of failures. This measurement is used to show how long equipment will function before requiring a repair.
Mean Time to Repair (MTTR)	The sum of repair time divided by the number of times a repair has taken place. This measurement is typically used to show how quickly repairs can be made once equipment has failed.
metering	The measuring active energy or reactive energy or both by a meter (apparatus and associated equipment), as approved by Measurement Canada.
Momentary Closed Transition Switching	The momentary interconnection (≤ 100 millisecond) of a DER system to the EPC Distribution System with the purpose of transferring load from the EPC Distribution System to the DER and then operating in stand-alone (emergency) mode or transferring load from the DER back to the EPC Distribution System.
NERC	North American Electric Reliability Corporation. Refer to website: www.nerc.com
Operating Procedures	The procedures for the operation of both the DER Facility and the Facilities relating to an interconnection, which may be revised from time to time by EPC upon written notice to the DER Provider and attached as a schedule to an Interconnection Agreement.

overfrequency	The abnormal operating state or system condition that results in a system frequency above the normal 60 Hz.
overvoltage	The abnormal operating state or system condition that results in a system voltage above the upper limit specified in CSA CAN3-235-83 (R2015).
parallel operation	the simultaneous energization of a PCC by the distribution system and the DER system.
paralleling device	A device (e.g., circuit breaker) operating under the control of a synchronizing function to electrically connect two energized power sources together.
per unit (pu) / percent of (%)	Quantity expressed as a fraction of a defined base unit quantity. For active power (active current), the base quantity is the rated active power (rated active current). For apparent power (current), the base quantity is the rated apparent power (rated current). For system frequency, the base quantity is the nominal frequency (i.e., 60.0 Hz in North America). Quantities expressed in per unit can be converted to quantities expressed in percent of a base quantity by multiplication with 100.
Person	An individual, firm, partnership, association, joint venture, corporation, trustee, executor, administrator or legal representative.
point of common coupling (PCC)	The point at which the EPC System is connected to the DER Facility or conductors, and where any transfer of electric energy between the DER Provider and EPC takes place. See Appendix 2 for more information.
point of connection (POC)	The point at which the DER(s) is/are connected within the DER facilities or conductors. Note there can be a single or multiple POC, see Appendix 2 for more information.
power factor	The ratio of real or productive power measured in kilowatts (kW) to total or apparent power measured in kVA.
power flow	The ratio of real or productive power measured in kilowatts (kW) to total or apparent power measured in kVA.
primary service	The electricity service provided to the customer in the service voltage of 1000V or above at the point-of-common-coupling of the serviced site.
protection scheme	Protection functions, including associated sensors, relaying, and power supplies, intended to protect a distribution system or interconnection equipment.
reactive power	The imaginary power in a capacitive or inductive load. It represents an energy exchange between the power source and the reactive loads where no net power is gained or lost. The net average reactive power is zero. Reactive power is stored in and discharged by inductive motors, transformers, solenoids and capacitors. Reactive inductive power is measured in volt-amperes reactive (VAR).

real time	The actual time during which and event or action takes place. Generally, referring to instantaneous review of processing of information.
resonance	A tendency of a system to oscillate at increased amplitude at certain frequencies, usually resulting in very high voltages and currents
ride-through	Ability to withstand voltage or frequency disturbances inside defined limits and to continue operating as specified.
Root Mean Square (RMS)	The equivalent mean value of a current or voltage waveshape. It is defined mathematically as the square root of the average of the square of the value of the function taken throughout one period. For a sinusoidal waveshape, the RMS value is equal to the peak value divided by 1.414.
secondary network system	A distribution system configuration that provides low-voltage service to Customers from a secondary voltage cable network typically supplied from multiple transformers connected to different feeders.
secondary service	The electricity service provided to the customer in the service voltage of less than 1000V at the PCC of the serviced site.
SLD	Single line diagram
Supervisory Control and Data Acquisition (SCADA)	A computing, communications, and visualization architecture used to monitor and control individual pieces of equipment as a system to ensure the system is working properly as a whole.
synchronous generation	An alternating-current machine in which the rotational speed of normal operation is constant, and when interconnected, is in synchronism with the frequency and in step with the voltage of the electric utility system.
System Impact Assessment (SIA)	A technical study done by EPC to assess the impacts of a Customer's DER Facility interconnection on the EPC Distribution System
Technical Requirements	The ENMAX Power Corporation Distributed Energy Resource Technical Interconnection Requirements document as well as any updates of DER technical interconnection requirements in the form of bulletins and/or amendments that are published periodically by EPC on its website.
transfer trip	A remote signal directed from an upstream device to command the interconnection system to disconnect from the distribution system.
trip	Disconnection from the distribution system. NOTE – DER should meet the re-enter service criteria before reconnection to the distribution system.
UL	Underwriters Laboratories. Refer to website: www.ul.com

underfrequency	The abnormal operating state or system condition that results in a system frequency below the normal 60 Hz.
undervoltage	The abnormal operating state or system condition that results in a system voltage below the lower limit specified in CSA CAN3-235-83 (R2015).
Volt-Ampere reactive (Var)	A unit by which reactive power is expressed in an AC electric power system.
vector surge	A transient variation of current, voltage, or power flow in an electric circuit or across an electric system (NERC). This can also be known as vector shift or out-of-step.
Voltage	The electrical force or potential that causes a current to flow in a circuit.
Voltage flicker	A condition of fluctuating voltage on a power system that can lead to noticeable fluctuations in the output of lighting systems.
Watt	The scientific unit of electric power.
WECC	Western Electricity Coordinating Council. Refer to website: www.wecc.biz

APPENDIX 2

Point-of-Common-Coupling and Point-Of-Connection Reference Points

Reference Point of Applicability (RPA)

There are three different reference points used throughout the Technical Requirements.

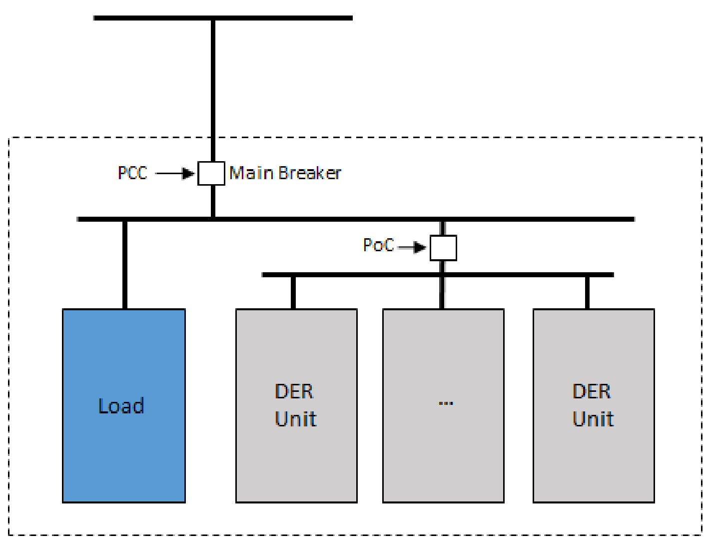
- The EPC/Customer Demarcation Point: This refers to the electrical point where EPC owned equipment connects to Customer owned equipment and indicates the installation, operation, and maintenance responsibilities for each entity.
- The Point of Common Coupling (PCC): This refers to the point where the customer owned DER power system connects to the EPC distribution system (typically a customer owned circuit breaker or switch).
- The Point of Connection (POC): This refers to the locations where the DER electrically connects to the distribution system within the customer facility (breaker, contactor or switch). Refer below for illustrations of typical PCC and POC location. The RPA is typically the PCC unless the DER meets the following exceptions: where the RPA is not the PCC, no device in-between the POC and PCC shall prevent the DER from meeting the disturbance ride-through requirements.

The following SLDs illustrates general ideas of Point-of-Common-Coupling (PCC) and Point-of-Connection (POC).

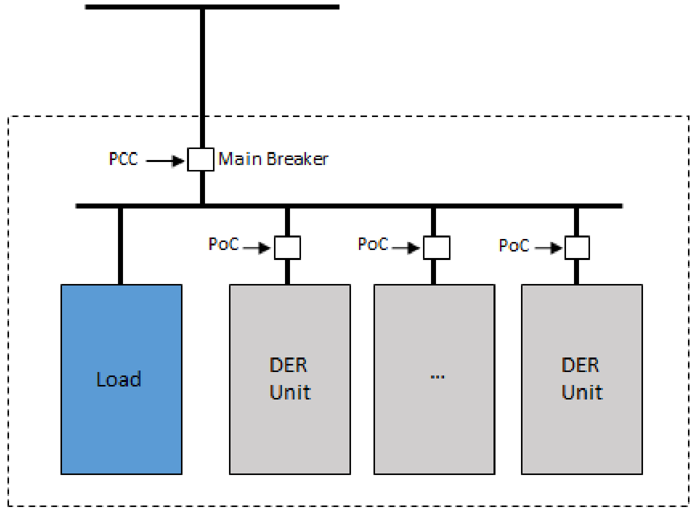
Notes for SLD:

1. Dotted rectangular shows the boundary of the property where loads and/or generation facilities are located; and, the SLDs assumes the wire ownership is divided by the property line
2. Supplemental DER support unit means any equipment that is used to comply with some or all of the interconnection requirements. This can include capacitor banks, STATCOMs, harmonic filters that are not part of a DER unit, protection devices, plant controllers, etc.

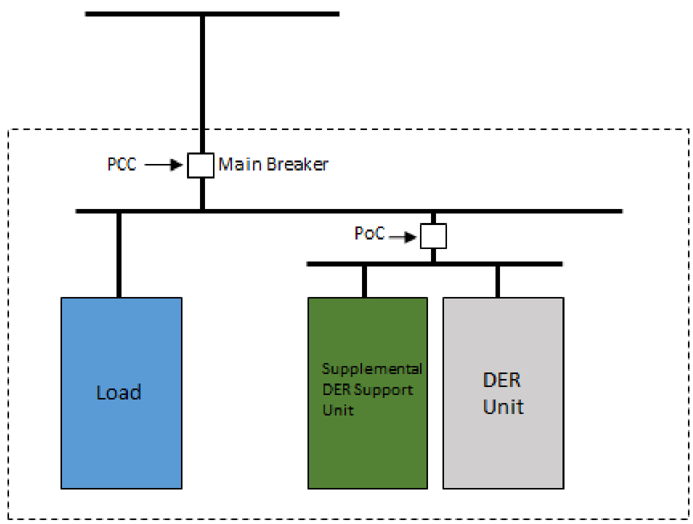
Type 1: With Generation Aggregation Point



Type 2: Without Generation Aggregation Point



Type 3: With Supplemental Support Unit



APPENDIX 3

Example DER Single Line Diagrams for Primary and Secondary Interconnection

Figure 5 - SLD for Primary Metered Interconnection

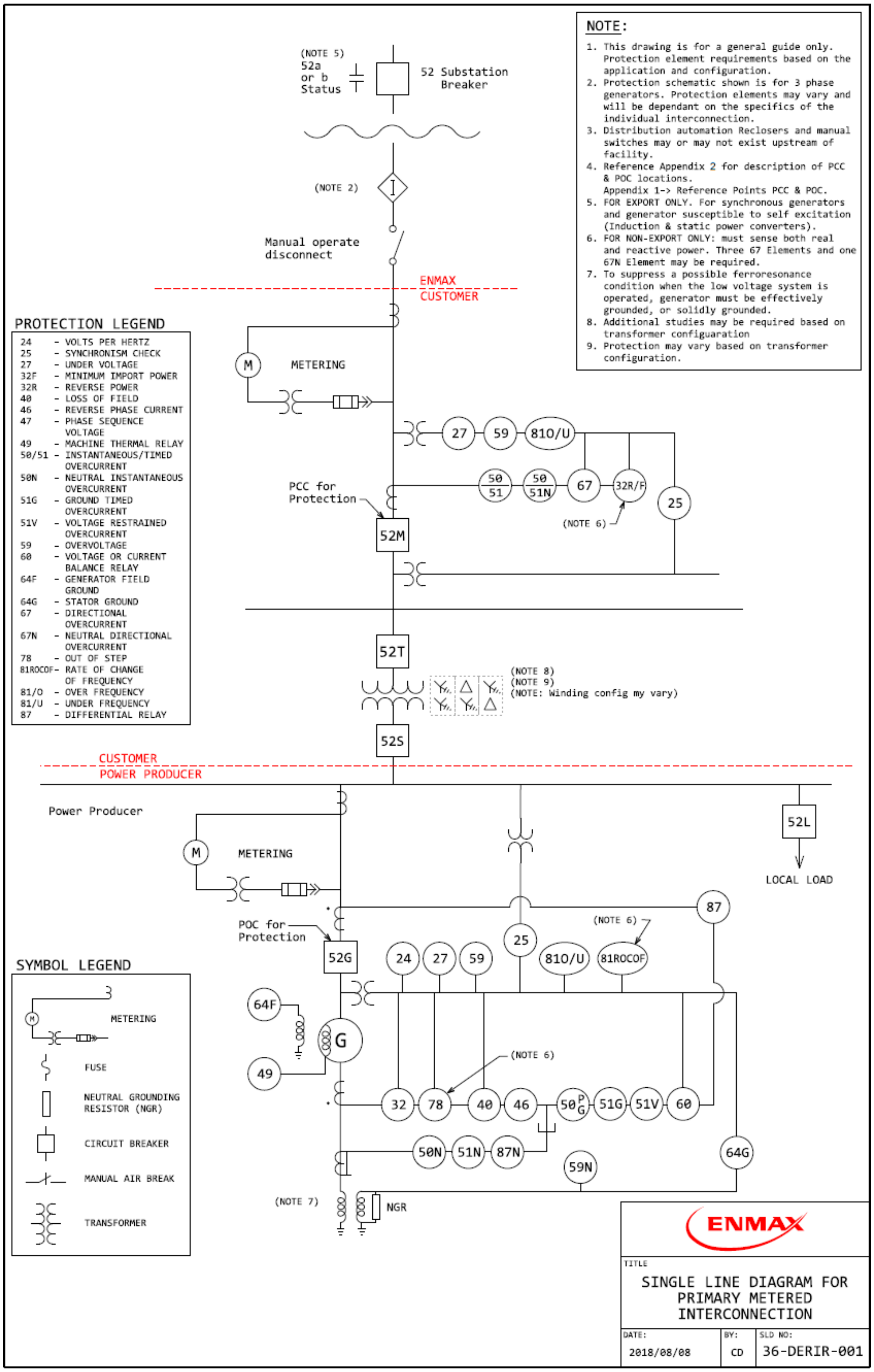


Figure 6 - SLD for Secondary Metered Interconnection

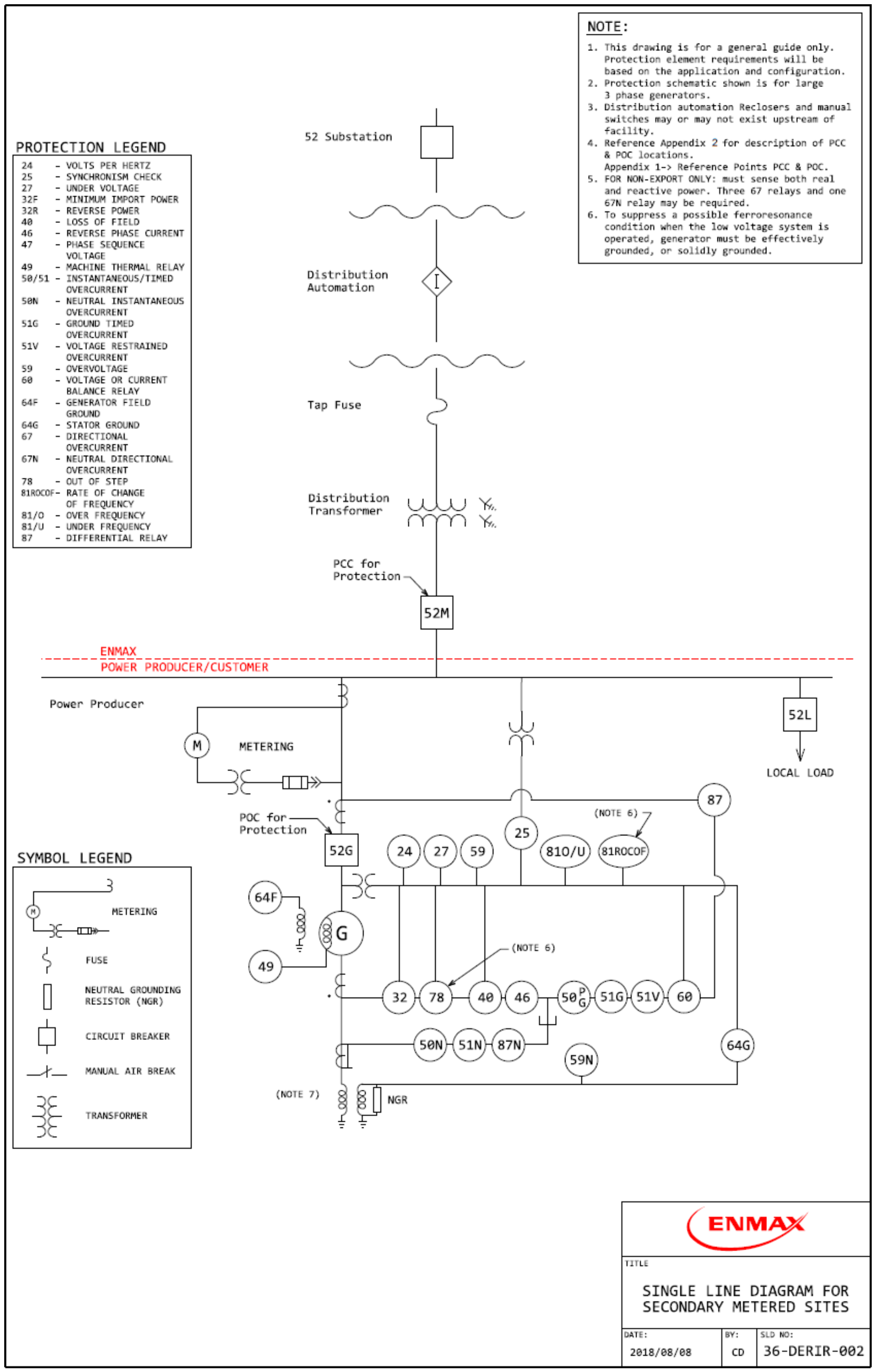


Illustration correciton note: PCC for Protection is within the customer's ownership and responsibility

APPENDIX 4

APPLICABLE CODES AND STANDARDS

The DER interconnection shall comply with the Technical Requirements and to the applicable sections of the following codes and standards. Specific types of interconnection schemes, DER technologies and the ENMAX Distribution System may have additional requirement, standards, recommended practices or guideline documents external to the Technical Document. The applicability and hierarchy of those, with respect to the requirements herein, are beyond the scope of the Technical Requirements. The list of indicated standards organizations and codes and standards referenced throughout the Technical Document is therefore not to be regarded as all-inclusive.

Standards Organizations:

- CSA (Canadian Standards Association)
- AESO (Alberta Electric System Operator)
- ECUC (Alberta Electrical and Communication Utility Code)
- Measurement Canada Standards
- IEEE (Institute of Electrical and Electronics Engineers)
- ANSI (American National Standards Institute)
- IEC (International Electrotechnical Commission)
- UL (Underwriters Laboratories)
- NEMA (National Electrical Manufacturers Association)

Codes and Standards:

- CAN/CSA C22.3 No. 9 Interconnection of Distributed Resources and Electricity Supply Systems
- Alberta Electrical Utility Code
- CSA C22.1-24 Canadian Electrical Code Part I, Safety Standard for Electrical Installations
- IEEE Std 1547 Interconnecting Distributed Resources with Electric Power Systems
- CSA Standard CAN3-C235-83 (R2015) Preferred Voltage Levels for AC systems 0 to 50 000V
- AESO Generation and Load Interconnection Standard
- EPC Power Quality Specifications and Guidelines for Customers, Sections 2.1 to 2.6
- ENMAX Power Quality Specifications and Guidelines for Customers

- IEEE Std 1453-2015 IEEE Recommended Practice for the Analysis of Fluctuating Installations on Power Systems
- IEEE/ANSI Std. C62.41.2 IEEE Recommended Practice on Characterization of Surges in Low-Voltage (1000 V and Less) AC Power Circuits
- IEEE Std. C37.90.1 IEEE Standard for Surge Withstand Capability (SWC) Tests for Relays and Relay Systems Associated with Electric Power Apparatus – Description
- CAN/CSA-C60044-6:2011 Instrument Transformers Part 6: Requirements for Protective Current Transformers for Transient Performance
- IEEE Std C57.13:2016 – IEEE Standard Requirements for Instrument Transformers
- IEEE Std. 142 – IEEE Recommend Practice for Grounding of Industrial and Commercial Power Systems
- CAN/CSA-C22.2-107.1 (R2011) General Use Power Supplies
- CAN/CSA-C22.2-257 (R2015) Interconnecting Inverter-Based Micro-Distributed Resources to Distribution Systems
- IEEE Std 1815-2012 - IEEE Standard for Electric Power Systems Communications-Distributed Network Protocol (DNP3)
- IRIG Standard 200-04 – IRIG Serial Time Code Formats
- IRIG-B Format B004
- IEEE Std 1344-1995
- International Electrotechnical Commission (IEC) Standard 61000-4-30 Class A - Power quality monitor: Development and performance analysis
- IEEE Std 1159-2009
- CAN/CSA-IEC 61000-4-15 Electromagnetic Compatibility (EMC) - Part 4: Testing and Measurement Techniques - Section 6: Immunity to Conducted Disturbances, Induced by Radio-Frequency Fields
- IEEE Std 1547 - 2018 - IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces
- IEEE Std 1547.1 - 2020 - IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems
- CAN/CSA 22.3 No.9 (2020) Interconnection of distributed resources and electricity supply systems

- UL 1741 Supplemental A (SA) and Supplemental B (SB) – Advanced Inverter Testing addition to Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources
- ENMAX Metering Standard
- CSA Z463-18 (2018) Maintenance of Electrical Systems
- AUC Micro-generation or Distributed Generation guidelines
- Electromagnetic Compatibility (EMC) standards
- Surge Withstand Capability (SWC) standards
- UL1973 (2022) Standard for Batteries for Use in Stationary, Vehicle Auxiliary Power and Light Electric Rail (LER) Applications
- UL9540 (2025) - Energy Storage Systems and Equipment
- UL9540a (2025)- Test Method for Battery Energy Storage Systems (BESS)UL1973 (2022) Standard for Batteries for Use in Stationary, Vehicle Auxiliary Power and Light Electric Rail (LER) Applications
- NFPA 855 (2026) - Standard for the Installation of Stationary Energy Storage Systems (2026)

APPENDIX 5

Common File Format for DER Settings Exchange and Storage_ Version 2.0 format of **Specified Settings** to be implemented typically for inverter based DERs permitted to operate at unity constant power factor. For other DERs ENMAX will provide DER facility specific Specificied Settings to the DER Provider. Blank values are not specified by ENMAX Power. Final settings need to be confirmed by ENMAX at least 10 working days prior to energization.

PARAMETER	VALUE
NP_P_MAX-SS	
NP_P_MAX_OVER_PF-SS	
NP_OVER_PF-SS	
NP_P_MAX_UNDER_PF-SS	
NP_UNDER_PF-SS	
NP_VA_MAX-SS	
NP_Q_MAX_INJ-SS	
NP_Q_MAX_ABS-SS	
NP_P_MAX_CHARGE-SS	
NP_APPARENT_POWER_CHARGE_MAX-SS	
NP_AC_V_NOM-SS	
AP_LIMIT_ENABLE-SS	DISABLED
AP_LIMIT-SS	
ES_PERMIT_SERVICE-SS	ENABLED
ES_V_LOW-SS	0.917
ES_V_HIGH-SS	1.05
ES_F_LOW-SS	59.5
ES_F_HIGH-SS	60.1
ES_RANDOMIZED_DELAY-SS	0
ES_DELAY-SS	300
ES_RAMP_RATE-SS	300
CONST_PF_MODE_ENABLE-SS	ENABLED
CONST_PF_EXCITATION-SS	ABS
CONST_PF-SS	1
CONST_Q_MODE_ENABLE-SS	DISABLED
CONST_Q-SS	
QV_MODE_ENABLE-SS	DISABLED
QV_VREF-SS	
QV_VREF_AUTO_MODE-SS	DISABLED
QV_VREF_TIME-SS	
QV_CURVE_V2-SS	

QV_CURVE_Q2-SS	
QV_CURVE_V3-SS	
QV_CURVE_Q3-SS	
QV_CURVE_V1-SS	
QV_CURVE_Q1-SS	
QV_CURVE_V4-SS	
QV_CURVE_Q4-SS	
QV_OLRT-SS	
QP_MODE_ENABLE-SS	DISABLED
QP_CURVE_P3_GEN-SS	
QP_CURVE_P2_GEN-SS	
QP_CURVE_P1_GEN-SS	
QP_CURVE_P1_LOAD-SS	
QP_CURVE_P2_LOAD-SS	
QP_CURVE_P3_LOAD-SS	
QP_CURVE_Q3_GEN-SS	
QP_CURVE_Q2_GEN-SS	
QP_CURVE_Q1_GEN-SS	
QP_CURVE_Q1_LOAD-SS	
QP_CURVE_Q2_LOAD-SS	
QP_CURVE_Q3_LOAD-SS	
PV_MODE_ENABLE-SS	DISABLED
PV_CURVE_V1-SS	
PV_CURVE_P1-SS	
PV_CURVE_V2-SS	
PV_CURVE_P2-SS	
PV_OLRT-SS	
OV2_TRIP_V-SS	1.2
OV2_TRIP_T-SS	0.16
OV1_TRIP_V-SS	1.1
OV1_TRIP_T-SS	2
UV1_TRIP_V-SS	0.88
UV1_TRIP_T-SS	10
UV2_TRIP_V-SS	0.45
UV2_TRIP_T-SS	0.16
OF2_TRIP_F-SS	62
OF2_TRIP_T-SS	0.16
OF1_TRIP_F-SS	61.2
OF1_TRIP_T-SS	300

UF1_TRIP_F-SS	58.5
UF1_TRIP_T-SS	300
UF2_TRIP_F-SS	56.5
UF2_TRIP_T-SS	0.16
PF_DBOF-SS	0.036
PF_DBUF-SS	0.036
PF_KOF-SS	0.05
PF_KUF-SS	0.05
PF_OLRT-SS	5
MC_HVRT_V1-SS	
MC_LVRT_V1-SS	

APPENDIX 6

Common File Format for DER Settings Exchange and Storage_ Version 2.0 format for **Applied Settings** to be provided to ENMAX Power by the DER provider. Final settings need to be confirmed by ENMAX Power prior to energization. As requested by ENMAX Power, DER Providers are to provide the DER settings that they have applied to their DER facility in the following format back to ENMAX Power for ENMAX Power's review. DER Provider to replace values in the Allow Values column with the values from their facility. Settings need to be confirmed by ENMAX at least 10 working days prior to energization. The information below is to be provided to ENMAX in comma separated variables (CSV) format.

	Parameter Label	Units	Data Type	Allowed Values
1.	NP_P_MAX-AS, NP_P_MAX	W	Number	
2.	NP_P_MAX_OVER_PF-AS, NP_P_MAX_OVER_PF	W	Number	
3.	NP_OVER_PF-AS, NP_OVER_PF		Number	
4.	NP_P_MAX_UNDER_PF-AS, NP_P_MAX_UNDER_PF	W	Number	
5.	NP_UNDER_PF-AS, NP_UNDER_PF		Number	
6.	NP_VA_MAX-AS, NP_VA_MAX	VA	Number	
7.	NP_NORMAL_OP_CAT-AS, NP_NORMAL_OP_CAT		Select-list	▪ CAT_A ▪ CAT_B
8.	NP_ABNORMAL_OP_CAT-AS, NP_ABNORMAL_OP_CAT		Select-list	▪ CAT_I ▪ CAT_II ▪ CAT_III
9.	NP_Q_MAX_INJ-AS, NP_Q_MAX_INJ	VAr	Number	
10.	NP_Q_MAX_ABS-AS, NP_Q_MAX_ABS	VAr	Number	
11.	NP_P_MAX_CHARGE-AS, NP_P_MAX_CHARGE	W	Number	
12.	NP_APPARENT_POWER_CHARGE_MAX-AS, NP_APPARENT_POWER_CHARGE_MAX	VA	Number	
13.	NP_AC_V_NOM-AS, NP_AC_V_NOM	Vac	Number	
14.	NP_AC_V_MAX-AS, NP_AC_V_MAX	Vac	Number	
15.	NP_AC_V_MIN-AS, NP_AC_V_MIN	Vac	Number	

16.	NP_SUPPORTED_MODES-AS, NP_SUPPORTED_MODES		Multi-list	▪ CONST_PF ▪ CONST_Q ▪ QV ▪ QP ▪ PV ▪ PF
17.	NP_REACTIVE_SUSCEPTANCE-AS, NP_REACTIVE_SUSCEPTANCE	Siemens	Number	
18.	NP_MANUFACTURER-AS, NP_MANUFACTURER		Text	
19.	NP_MODEL-AS, NP_MODEL		Text	
20.	NP_SERIAL_NUM-AS, NP_SERIAL_NUM		Text	
21.	NP_FW_VER-AS, NP_FW_VER		Text	
22.	AP_LIMIT_ENABLE-AS		Select-list	▪ ENABLED ▪ DISABLED
23.	AP_LIMIT-AS	P p.u.	Number	
24.	ES_PERMIT_SERVICE-AS		Select-list	▪ ENABLED ▪ DISABLED
25.	ES_V_LOW-AS	V p.u.	Number	
26.	ES_V_HIGH-AS	V p.u.	Number	
27.	ES_F_LOW-AS	Hz	Number	
28.	ES_F_HIGH-AS	Hz	Number	
29.	ES_RANDOMIZED_DELAY-AS	s	Number	
30.	ES_DELAY-AS	s	Number	
31.	ES_RAMP_RATE-AS	s	Number	
32.	CONST_PF_MODE_ENABLE-AS		Select-list	▪ ENABLED ▪ DISABLED
33.	CONST_PF_EXCITATION-AS		Select-list	▪ INJ ▪ ABS
34.	CONST_PF-AS		Number	
35.	CONST_Q_MODE_ENABLE-AS		Select-list	▪ ENABLED ▪ DISABLED
36.	CONST_Q-AS	VAr p.u.	Number	
37.	QV_MODE_ENABLE-AS		Select-list	▪ ENABLED ▪ DISABLED
38.	QV_VREF-AS	V p.u.	Number	
39.	QV_VREF_AUTO_MODE-AS		Select-list	▪ ENABLED ▪ DISABLED
40.	QV_VREF_TIME-AS	s	Number	
41.	QV_CURVE_V2-AS	V p.u.	Number	

42.	QV_CURVE_Q2-AS	VAr p.u.	Number	
43.	QV_CURVE_V3-AS	V p.u.	Number	
44.	QV_CURVE_Q3-AS	VAr p.u.	Number	
45.	QV_CURVE_V1-AS	V p.u.	Number	
46.	QV_CURVE_Q1-AS	VAr p.u.	Number	
47.	QV_CURVE_V4-AS	V p.u.	Number	
48.	QV_CURVE_Q4-AS	VAr p.u.	Number	
49.	QV_OLRT-AS	s	Number	
50.	QP_MODE_ENABLE-AS		Select-list	▪ ENABLED ▪ DISABLED
51.	QP_CURVE_P3_GEN-AS	P p.u.	Number	
52.	QP_CURVE_P2_GEN-AS	P p.u.	Number	
53.	QP_CURVE_P1_GEN-AS	P p.u.	Number	
54.	QP_CURVE_P1_LOAD-AS	P p.u.	Number	
55.	QP_CURVE_P2_LOAD-AS	P p.u.	Number	
56.	QP_CURVE_P3_LOAD-AS	P p.u.	Number	
57.	QP_CURVE_Q3_GEN-AS	VAr p.u.	Number	
58.	QP_CURVE_Q2_GEN-AS	VAr p.u.	Number	
59.	QP_CURVE_Q1_GEN-AS	VAr p.u.	Number	
60.	QP_CURVE_Q1_LOAD-AS	VAr p.u.	Number	
61.	QP_CURVE_Q2_LOAD-AS	VAr p.u.	Number	
62.	QP_CURVE_Q3_LOAD-AS	VAr p.u.	Number	
63.	PV_MODE_ENABLE-AS		Select-list	▪ ENABLED ▪ DISABLED
64.	PV_CURVE_V1-AS	V p.u.	Number	
65.	PV_CURVE_P1-AS	P p.u.	Number	
66.	PV_CURVE_V2-AS	V p.u.	Number	
67.	PV_CURVE_P2 -AS	P p.u.	Number	
68.	PV_OLRT-AS	s	Number	
69.	OV2_TRIP_V-AS	V p.u.	Number	
70.	OV2_TRIP_T-AS	s	Number	
71.	OV1_TRIP_V-AS	V p.u.	Number	
72.	OV1_TRIP_T-AS	s	Number	
73.	UV1_TRIP_V-AS	V p.u.	Number	
74.	UV1_TRIP_T-AS	s	Number	
75.	UV2_TRIP_V-AS	V p.u.	Number	
76.	UV2_TRIP_T-AS	s	Number	
77.	OF2_TRIP_F-AS	Hz	Number	
78.	OF2_TRIP_T-AS	s	Number	

79.	OF1_TRIP_F-AS	Hz	Number	
80.	OF1_TRIP_T-AS	s	Number	
81.	UF1_TRIP_F-AS	Hz	Number	
82.	UF1_TRIP_T-AS	s	Number	
83.	UF2_TRIP_F-AS	Hz	Number	
84.	UF2_TRIP_T-AS	s	Number	
85.	PF_DBOF-AS	Hz	Number	
86.	PF_DBUF-AS	Hz	Number	
87.	PF_KOF-AS		Number	
88.	PF_KUF-AS		Number	
89.	PF_OLRT-AS	s	Number	
90.	MC_HVRT_V1-AS	V p.u.	Number	
91.	MC_LVRT_V1-AS	V p.u.	Number	

APPENDIX 7

Typical Volt-Var and Volt-watt requirement for DER projects where required by ENMAX Power

In order to maintain system power quality and reliability, where determined by ENMAX Power, DER facilities are to operate using both Volt-Var (voltage-reactive power mode) and Volt-Watt (voltage-active power mode), example shown in figure 3.

When required, the following settings for Volt-Var and Volt-Watt mode, with reactive power priority, are to be implemented unless other settings are determined by ENMAX Power through the interconnection process. These settings are to be documented, implemented and commissioned to confirm the DER will operate as intended:

Table 1: Settings for Volt-Var

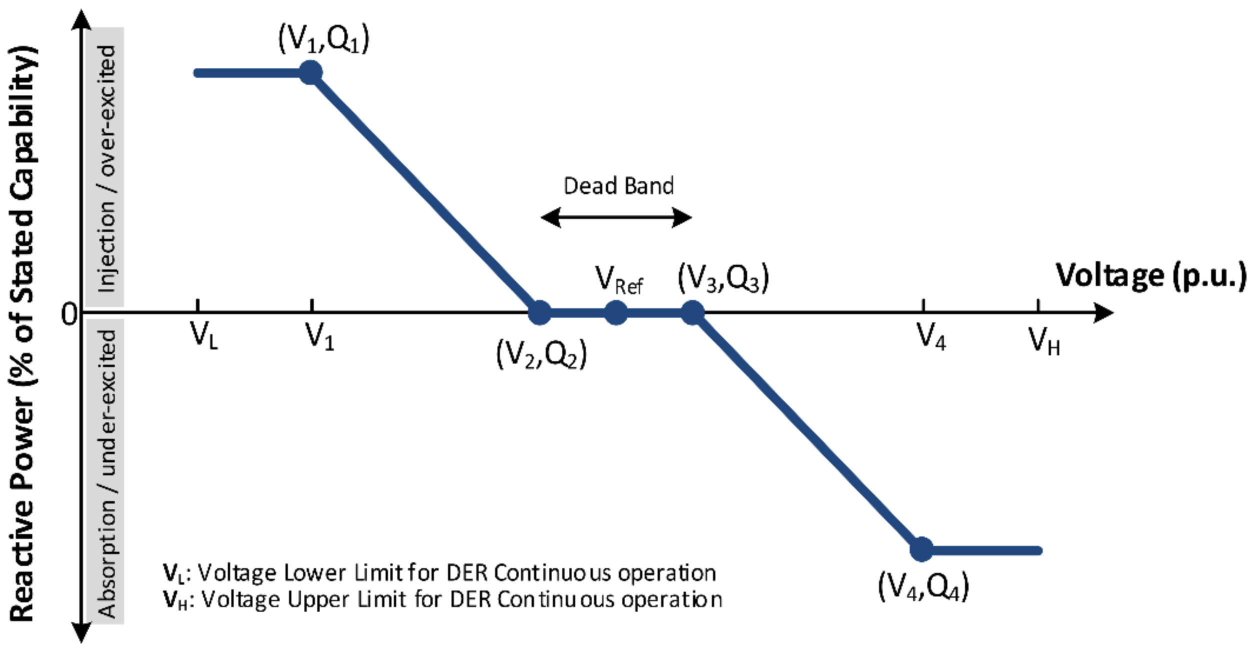
Voltage-Var mode Parameters	**Setting**
VRef	**VN= 1 pu**
V2	**VRef – 0.02VN = 0.98 pu**
Q2	**0**
V3	**VRef + 0.02VN = 1.02 pu**
Q3	**0**
V1	**VRef – 0.08VN = 0.92 pu**
Q1	**44% of nameplate apparent power rating, injection**
V4	**VRef + 0.042VN = 1.042 pu**
Q4	**44% of nameplate apparent power rating, absorption**
Open Loop Response Time	**5 s**

Table 2: Settings for Volt-Watt

Voltage-Watt mode Parameters	**Setting**
V1	1.042VN

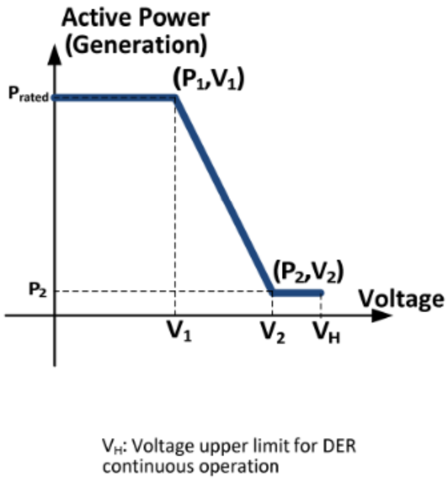
P2	Prated
V2	1.1 VN
Q3	0
Open Loop Response Time	10 s

Figure 1: Volt-Var power characteristic illustration



Reference: Figure H.5 IEEE 1547 [2018]

Figure 2: Volt-Watt power characteristic illustration



Reference: Figure H.5 IEEE 1547 [2018]

Figure 3: Example of Volt-Var and Volt-Watt functions both enabled