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Distributed Energy Resource Technical Requirements

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REVISION SHEET

Revision	Description	Date	Initial
0	Original Document	2002-11-09	fk/df
1	Schematic Revision (All figures) Addition of Introduction section Addition of Group III Connection Process Document format standardization Integrate with Distribution System Code (OEB) (revised September 9th, 2004)	2005-02-02	fk/csm
2	Removed business processes	2010-02-01	dr/be
3	General revision; Harmonize with updates to CSA C22.3 No. 9, IEEE 1547 and DSC, removed connection processes	2022-08-26	rh/ead
4	DERCP V2 updates(CIA and DER definitions), 8.1.1 TT, Minimum load requirement sec 7.4	2025-05-29	sm/ra/rh
5	UL 1741 SA (minimum) and SB (preferred) certification updated requirement for inverter based DERs, Bidi Meter requirements	2025/09/26	fk/sm/ra/rh
6	Definitions, Monitoring only MCB requirement for 50-200kW to bi-di metering for monitoring, DERCP V3	2026/04/15	sm/mc/rh

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1. Introduction

This technical guideline is intended to assist the Customer in understanding the technical requirements for connecting a Customer's Distributed Energy Resource (DER) to Hydro Ottawa Limited's (HOL) Distribution System. This guideline does not provide the details of costs or responsibilities that the Customer may assume; such details will be evaluated for each specific request.

Connection to the Distribution System is categorized according to size of the DER, and is set by the OEB's DSC according to the following table:

Table 1-1: OEB DSC Generation Categories

Category	Description	Category Criteria
1	Micro generation	All generation* less than or equal to 12 kW
2	Small Generation	1.) All generation* less than or equal to 500 kW for connections at voltages less than 15 kV. 2.) All generation* less than or equal to 1 MW for connections at voltages greater than 15 kV
3	Mid-Sized Generation	1.) All generation* greater than 500 kW but less than or equal to 10 MW for connections at voltages less than 15 kV. 2.) All generation* greater than 1 MW but less than or equal to 10 MW for connections at voltages greater than 15 kV.
4	Large Generation	All generation* greater than 10 MW

'* generation = DER energy sources

HOL's general requirements of a Customer connecting a DER are listed in Section 3.4 of HOL's Conditions of Service (ECS0012).

Any Customer that is considering installing a DER must contact HOL and ESA to collect all pertinent requirements. Submit a request for a DER connection by filling out a Preliminary Consultation Information Request (PCIR) on HOL's website (www.hydroottawa.com). If you have any general questions, reach out to DER@hydroottawa.com.

To clarify the technical requirements for connection, each section specifies the basic requirements for DER integration for each category size. For details on the connection process, refer to the OEB DER Connection Process (DERCP).

2. Reference

The following documents are referred to in this guideline:

CSA	C22.2 No. 107.1	*Power conversion equipment*
CSA	C22.3 No. 9	*Interconnection of Distributed Resources and Electricity Supply Systems*
CSA	C235	*Preferred voltage levels for AC systems up to 50 000 V*
Electricity Safety Authority (ESA)		*Ontario Electrical Safety Code (OESC)*
Government of Canada		*Electricity and Gas Inspection Act (R.S.C., 1985, c E-4)*

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Hydro Ottawa	ECG0008	*Distribution System Voltage and Power Quality*
Hydro Ottawa	ECS0012	*Hydro Ottawa Limited Conditions of Service*
Hydro Ottawa	GCS0043	*HOL Monitoring and Control Box (MCB) Installation - Construction Detail*
Hydro Ottawa	GCS0048	*HOL Monitoring and Control Box (MCB) Model B Installation with Contactor – Construction Detail*
Hydro Ottawa	GCS0051	*HOL Monitoring and Control Box (MCB) Model B Installation with Circuit Breaker – Construction Detail*
Hydro Ottawa	GDS0018	*DER Service Options*
IEEE	1547	*IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces*
Independent Electricity System Operator (IESO)		*Market Rules*
Ontario Energy Board (OEB)		*Distribution System Code (DSC)*
Ontario Energy Board (OEB)		*Distributed Energy Resources Connection Procedures (DERCP)*
UL	1741 SA & SB	*Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources*

3. Scope

This technical standard is intended to aid the Customer in understanding all the requirements necessary to successfully connect a non-standby, non-emergency-use-only DER project from concept to energization. Content relates requirements to each DER type for each size category. This standard shall be used in conjunction with the OEB Distributed Energy Resources Connection Process (DERCP). Hydro Ottawa does not currently offer connections under the Flexible Hosting Capacity (FHC) model outlined in the OEB's DERCP. Although Hydro Ottawa does not currently offer connections under the FHC model, it will identify potential options - where available - to address hosting capacity constraints and technical limits. When applicable, Hydro Ottawa will also provide a resolution plan and expected timelines to address the limitation.

4. Definitions

Connection Impact Assessment (CIA) means a study performed by or on behalf of the distribution company to assess the impact of a proposed DER (generation or energy storage facility) connection on its system. The CIA will specify technical requirements for the connection. A CIA may be required for other DER interconnections, including back-up or standby generation, especially in closed transition when coordination with HOL is required. These cases will not follow the DSC timeline.

Customer is defined in the *Conditions of Service*.

Distribution System is defined in the *Conditions of Service*.

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Distributed Energy Resource (DER) means an energy (typically electricity) source that is connected to a Grid for the purpose of providing energy or power to the Grid. A DER is connected on the customer-side of an ownership demarcation point either as a standalone to supply the Grid, or in parallel with premise load to primarily satisfy self-consumption. DERs include energy sources or sinks, and may include flexible (demand response managed) loads.

Grid means as defined in the *Conditions of Service*.

HOL means Hydro Ottawa Limited.

IESO means the Independent Electricity System Operator in the Province of Ontario

Island Operation means the operating condition of an energy source unit or units when supplying a load (loads) that is (are) not synchronized with the HOL Distribution System.

Isolating Device means a circuit breaker or disconnect switch of appropriate rating, which may be locked in the open position and whose configuration provides a clear visible point of disconnection between the generating unit and the HOL Distribution System.

Loss-of-Phase (LoP) means that one or two phases of a three-phase Grid, or a one of two poles in a bi-pole service, losses supply from an energy source.

Large Generation means as defined in Table 1,1 herein, considering the aggregated DER capacity within the same premise.

Micro Generation means as defined in Table 1,1 herein, considering the aggregated DER capacity within the same premise.

Mid-size Generation means as defined in Table 1,1 herein, considering the aggregated DER capacity within the same premise.

Momentarily means less than or equal to 100 milliseconds

OEB means the Ontario Energy Board

Open Transition Transfer Switch means a switch that disconnects load or an energy source from the Distribution System by breaking parallel and then making parallel between the Grid.

Ownership Demarcation Point means as defined in the *Conditions of Service*.

Parallel Operation means the connection and operation of the DER in electrical parallel with the Grid.

Permanently means greater than 100 milliseconds

Point of Common Coupling (PCC) — the point where the supply authority's system is connected to the power producer's facilities or conductors.

Point of (DER) Connection (PoC) — the point where an interconnection system is electrically connected to the power producer’s facility.

Professional Engineer means a person who holds a license or temporary license under the Ontario *Professional Engineers Act*

Small Generation means as defined in Table 1.1 herein.

Soft (Closed) Transition Switch means a switch that momentarily or permanently connects the DER to the Distribution System by making parallel and then breaking parallel.

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Synchronism means the condition that exists when the voltage magnitudes, phase rotation, and phase angles of the HOL Grid are identical to that of the DER(s) or the DER transformer(s) at the point where the units are synchronized.

5. Interconnection

5.1. Fundamental Requirements

All DER's which are interconnected (ie. parallel operation) with the grid shall conform to the requirements contained within this document. The inverter or any type of DER's name plate must be visible during commissioning to verify certification.

The safety and protective features of all inverter units must be certified according to UL 1741 (SA as a minimum). The inverters shall additionally demonstrate compliance with IEEE 1547 the version applicable at the time of application, establishing foundational performance and interconnection criteria as discussed in further detail within this document. Furthermore, local installation and operational procedures, as stipulated in Section 84 of the OESC, are also mandatory to ensure proper integration and ongoing safety within the electrical distribution system.

5.2. Isolation at the Point of Common Coupling

The PCC and PoC shall be identified in the design and on the single line diagram. HOL shall coordinate design, construction, maintenance and operation of the facilities on its side of the PCC. The Customer is responsible for the design, construction, maintenance and operation of the facilities on its side of the PCC unless described otherwise in a generator connection agreement.

The equipment on the Customer's side of the PCC shall be approved in accordance with Rule 2-024 of the OESC.

A disconnecting means must be provided by the Customer and must be in compliance with the OESC. Additionally, HOL must be able to isolate all parts of the Customer's electrical system with this disconnecting means to satisfy safety and safe working procedures. To comply with these requirements, the Customer must install a disconnect switch that can be opened, locked and tagged by the utility. This switch must be a "load-break" switch with the appropriate ratings and conform to OESC Rule 84-024. Where the DER connects to the Distribution System side of the customer's main disconnect, the DG System Disconnect Switch must be service entrance rated; fusing is dependent on the OESC.

The location of the disconnect switch shall be agreed upon by the Customer and HOL to ensure that it is readily accessible to HOL at all times and meets HOL clearance requirements. The disconnect switch must be capable of providing a visible point of disconnect either through a viewing window or by opening the front cover; an indicator is not acceptable.

5.3. Grounding

DER and their associated interconnection systems must be grounded according to the manufacturer's recommendations and meet requirements set out by the OESC.

Interconnection of three-phase transformers, and transformer grounding systems on three-phase Distribution Systems shall be co-coordinated with HOL and shall not cause voltage disturbances or disrupt co-ordination of the Distribution System ground fault protection.

6. Power Quality

The DER shall not significantly impact the power quality at the PCC and shall meet all the requirements set out in CSA C22.3 No. 9. If there are negative impacts once the DER is in service, the DER shall be left

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isolated from the Grid until appropriate measures have been taken to prevent negative impacts to the Distribution System and thus, the Customers it serves.

All costs required to mitigate problems due to power quality will be the responsibility of the Customer.

6.1. Harmonics

DERs shall remain below the allowable harmonic distortion limits set forth in CSA-C22.3 No.9. If the DER exceeds these limits, corrective action by the Customer will be required unless otherwise deemed by HOL.

6.2. Voltage Flicker

Voltage flicker caused by the Customer's DER must remain within the limits set in HOL's ECG0008 guideline. In the event that voltage variations are experienced due to the presence of the DER, HOL will require the Customer to either remedy the problem or disconnect the equipment.

Loss of synchronism protection may be required to be incorporated by the Customer to limit flicker.

6.3. Voltage Regulation

The Customer is to ensure that their connected DER shall meet HOL's standard ECG0008 for system voltage - including satisfactory operation within the extreme voltage level variation limits and power quality.

6.3.1. Fundamental Frequency

The DER must operate at a nominal frequency of 60 Hz with a maximum frequency drift of +/- 0.05% unless required to support the Grid. In the latter case, the agreed low and extreme low frequency ride through thresholds shall meet IEEE 1547 default unless agreed to in writing by HOL.

6.3.2. Steady-state Voltage

The steady state operating voltage of the DER must be maintained within the limits set out in ECG0008, unless required to support the Grid. In the latter case, the agreed low and extreme low voltage ride through thresholds shall meet IEEE 1547 default unless agreed to in writing by HOL.

HOL has a responsibility to provide appropriate Distribution System steady state service voltage levels to all Customers, with or without a DER, connected to a HOL feeder as per CSA Standard CAN3-C235.

6.3.3. Voltage Fluctuation

Adequate voltage regulation shall be maintained under a variety of operating conditions. During normal operation, and whenever possible, the DER shall be loaded and unloaded gradually to allow adequate time for regulating devices to respond. Details will be provided by HOL throughout the connection process.

6.3.4. Voltage Unbalance

The operation of single and three phase DERs shall not cause objectionable voltage unbalances as per CSA C22.3 No. 9.

Where the Distribution System supplies single-phase loads, some unbalances are inevitable. The DER shall be capable of operating under these conditions and shall at all cost not cause further deterioration of existing unbalanced conditions.

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6.4. Power Factor

The DER power factor setting shall ensure that the power factor at the PCC meets the requirements of ECG0008, unless otherwise stated by HOL (see Distribution System Support section herein). A lagging power factor below 0.9 at the PCC may result in billing penalties, depending on the HOL's rate structure. A leading power factor indicates that the DER is supplying capacitive reactive power to the Grid. Currently, HOL does not provide compensation for DERs supplying reactive power. The DER power factor setting can be carefully considered depending upon whether the project is connected within the customers load facility or in parallel.

If the DER disturbs the Distribution System voltage levels at the PCC then the Customer may be required to operate its facility within a smaller power factor range or take other compensatory measures. Field settable fixed and dynamic power factor correction techniques may be used if consultation with HOL reveals no adverse effect on the Distribution System.

Generation excitation equipment shall be capable of operating in an automatic voltage control mode and power factor control mode. HOL may require specific power factor settings for the DER.

6.5. Limitation of DC Injection

Per IEEE 1547, the DER shall not inject a DC current greater than 0.5% of the unit rated output current.

6.6. Protection from Electromagnetic Interference

Per CSA C22.3 No. 9, the influence of electromagnetic interference should not interfere with operation of the DER's interconnection system.

6.7. Surge Withstand Performance

Per CSA C22.3 No. 9 and OESC 84-014, the interconnection system shall have the capability to withstand voltage and current surges.

6.8. Paralleling Device

Per IEEE 1547, the interconnection system paralleling-device shall be capable of withstanding 220% of the interconnection system rated voltage.

7. Protection

HOL requires that any element of the interconnection system external to the DER, but ahead of the PoC be installed in a fail-safe manner with self-checking features or redundant protection functions.

The Customer shall provide a document describing the protections in place to detect and compensate (see Distribution System Support section herein) or clear the following conditions as per CSA C22.3 No. 9:

a) Balanced and unbalanced system faults;
b) Frequency variations;
c) Voltage variations; and
d) Unauthorized Islanding conditions

Additional protection schemes might be required to detect additional conditions and shall be at the discretion of HOL for the purpose of maintaining Distribution System integrity and employee safety.

All fault current interrupting devices shall be adequately sized to account for fault contributions from the

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DER system and the Distribution System. HOL shall provide present and anticipated fault contributions from the Distribution System at the PCC or shall provide the necessary information for the fault contributions at the PCC to be calculated.

The primary connection of the DER transformer should be considered when selecting and setting DER protections. HOL will verify settings at PCC if applicable. The Customer must conduct commissioning tests witnessed by HOL, and provide all test results to HOL for review prior to energization of the DER. A letter signed by the commissioning agent indicating that all protections have been applied and tested per the protection schema provided to and accepted by HOL.

7.1. Protection Requirements

The protection requirements in this section are the minimum requirements for protecting HOL's people, equipment and Distribution System. Though not reviewed by HOL, the Customer shall also consider any additional protection needed to also comply with ESA obligations keeping in mind people, equipment and process safety and loss.

7.1.1. Minimum protection

All DERs shall have the following protections as a minimum to meet CSA C22.3 No. 9:

a) Undervoltage
b) Overvoltage
c) Underfrequency
d) Overfrequency
e) Overcurrent

Definitions and trip requirements for each of these can be found in CSA C22.3 No. 9.

The subsequent sections shall specify more protections based on the type of DERs.

7.1.2. Single Phase DERs

All single phase DERs shall meet the minimum protection requirements in Table 15-1.

Table 15-1: Single-Phase Minimum DER Protection Requirements

ANSI Device ID#:	Description
21*	Distance Relay
25	Synchronizing Verification
27	Undervoltage
50/51	Overcurrent
59	Overvoltage
81O	Overfrequency
81U	Underfrequency
	Unauthorized Islanding

* If required as per CIA

7.1.3. Three-Phase DERs

All three-phase DERs shall meet the minimum protection requirements in Table 15-2 with the goal of maintaining balanced three-phase output under all operating conditions - unless authorized by HOL - detecting low voltage in one or more phases and automatically cease to energize all phases from the interconnected system when a fault is detected.

Table 15-2: Three-Phase Minimum DER Protection Requirements

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ANSI Device ID#:	Description	Synchronous	Induction	Inverter Based
25	Synchronizing Verification	X	X[a]	X[a]
21	Distance Relay	To be determined for each project		
27	Undervoltage	X	X	X
32R	Reverse Power	X[c]	X[c]	X[c]
46	Negative Sequence Current	X	X	X[d]
50	Instantaneous Overcurrent	X	X	X[b]
51V	Voltage Restrained Time Overcurrent	X	X	X[b]
59	Overvoltage	X	X	X
60*	Voltage or Current Balance	To be determined for each project		
67	Directional Phase Overcurrent	X	X	X[e]
67N	Neutral Directional Overcurrent	X	X	X[e]
69	Close Blocking Relay	To be determined for each project		
78	Voltage Phase Angle Measuring	≥ 500 kW	≥ 500 kW	
81O	Overfrequency	X	X	X
81U	Underfrequency	X	X	X
81R	Rate-of-Change Frequency	≥ 500 kW	≥ 500 kW	
85	Transfer Trip	To be determined for each project		

[a] – Required if not controlled by power electronics to match HOL system voltage with magnitude, phase angle, and frequency
[b] – Not required if DER has appropriately set overcurrent setting
[c] – Not required for exporting DERs
[d] – See section 7.2 for LoP relay requirements.
[e] – Not required if the DER has reverse power protection preventing generation onto the Grid.
* - Loss of potential protection is required where there are upstream fuses used as protective devices (such as for transformer protection). The loss of potential relays shall consist of three single-phase relays.

7.1.4. Soft Transition Switching

DER systems that are parallel with the Grid for six cycles (100 ms) or less shall have the following protection functions:

a. Undervoltage protection, which shall ensure that the DER system is not energizing HOL's de-energized Grid;
b. a six-cycle maximum delay timer to prevent paralleling with HOL Grid longer than six cycles;
c. a manual or automatic synchronization check, and;
d. MCB or TT for monitoring the following, see Section 9 for details.
    i. transition breakers (main, DER) to ensure that paralleling is not > 100 ms.
    ii. the power output of the DER (see monitoring section herein) .

Additionally to the above functions, the Customer is responsible for protecting their DER per ESA requirements.

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7.2. Phase and Ground Fault

The DER shall be able to detect and cease energization of the Distribution System as stated in CSA C22.3 No. 9.

Single-phase inverter based DERs connecting to a single-phase Distribution System shall not require an independent LoP device.

An independent LoP device, in addition to the inherent feature of the DER, shall be required if one or more of the following apply:

- The HOL side of the Interface Transformer is of delta or tee configuration; OR
- There is more than one inverter in the DER configuration; OR
- It is deemed required by OESC or ESA; OR
- There is an Intermediate Transformer present between the Interface Transformer and the inverter(s).

The LoP should be installed on the DER side of the DG Source Disconnect immediately after the Monitoring and Control Box (MCB) sensors (when applicable). In the case where no MCB is present, the LoP is to be installed directly after the DG Source Disconnect. All Customer owned equipment is to be installed on the DER side of the LoP.

When present, the same Customer owned sensors and contactors for the MCB can be used for this LoP device.

7.3. Synchronization

The DER shall parallel with the Distribution System only when it meets the voltage magnitude, frequency, and phase angle difference tolerance requirements specified by CSA C22.3 No. 9 and IESO requirements.

The Customer shall conform to the OESC rule 84-006 which covers the synchronization of parallel DERs. Deviations in any parameter tolerance need substantiating by a Professional Engineer in good standing proving that the net energy, including equivalent energy, is the same or less than the resultant equivalent in the IEEE 1547 synchronization requirements .

7.4. Anti-Islanding Protection

The Customer shall not island without permission from HOL. The DER shall comply with CSA C22.3 No. 9 for anti-islanding protection, ensuring the DER ceases to energize the Grid in the event of an unauthorized island.

For DERs where the aggregate facility capacity exceeds 50% of the minimum feeder load, as determined during the CIA, additional anti-islanding protections may be required to mitigate the risk of unauthorized islanding. These protections will be specified by HOL based on the CIA results, which shall include an analysis of feeder load conditions and fault contributions. Inverter-based DERs equipped with grid-sensing capabilities, LoP protection, and an HOL-controlled MCB may satisfy anti-islanding requirements without additional measures, provided the aggregate capacity is less than or equal to 50% of the minimum feeder load and other HOL requirements are met.

If Transfer Trip is required as an anti-islanding measure per the conditions outlined in the 8.1.1 Transfer Trip section, it shall be coordinated with the anti-islanding protection scheme. The Customer shall provide documentation, sealed by a Professional Engineer confirming that all anti-islanding protections have been tested and comply with CSA C22.3 No. 9, and HOL requirements.

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8. Cease to Energize

HOL makes use of automatic reclosers to maintain the reliability of the Distribution System. The Customer must be aware of line re-closing when designing the system protection schemes to ensure that their DER disconnects from the Distribution System prior to automatic re-close of the Distribution System's breakers or line reclosers. HOL shall review to ensure that the Customer's design shall de-energize the DER prior to auto-re-close operation of feeder tripping devices.

After a disturbance on the Distribution System, no reconnection shall take place without satisfying Synchronization requirements discussed herein. At anytime a DER is to re-connect to the Distribution System, the re-connection must be delayed for a period prescribed by Hydro Ottawa, which will be included in the DER connection agreement. The reason for the time delay is to allow the Distribution System to return to, or remain in, a normal operating state in the event of a prior disturbance.

HOL will review the Customer's proposed design to ensure that the DER will cease to energize automatically from the Distribution System's supply under the conditions described in this section.

8.1. Transfer Trip

A HOL installed Transfer Trip (TT) and associated communication equipment may be required to facilitate the loss of (Grid) supply detection resulting in an unauthorized island and provide a disconnect signal to the Customer. Determination of TT requirements will be made at the CIA phase of the process.

Transfer Trip Philosophy and Application:

Transfer Trip is applied to DER installations to ensure reliable and deterministic disconnection of the DER during abnormal system conditions, including loss of supply and potential islanding scenarios. The use of TT supports coordination with HOL's distribution system protection schemes, including automatic reclosing devices, and ensures system safety, reliability, and operability.

The requirement for TT is based on the size of the DER installation and its impact on the distribution system, including feeder loading, fault contribution, and islanding risk. These requirements are aligned with industry practices and are consistent with the principles outlined in the Hydro One Networks Inc. Distributed Generation Technical Interconnection Requirements (TIR) DT-10-015 R3, which recognize TT as an effective method for ensuring predictable anti-islanding performance where local protection schemes may not be sufficient.

TT is required for DER projects when one or more of the following conditions are met:

a) The aggregate DER facility capacity is 1 MW or larger; OR

b) The aggregate DER facility capacity exceeds 50% of the minimum feeder load; OR

c) The existing reclosing interval of the feeder breaker and/or upstream recloser(s) is less than 1.0 second.

For inverter-based DERs with grid-sensing capabilities, LoP protection, and an HOL-controlled MCB, TT may not be required if the above conditions are not met, subject to verification through the CIA. The CIA will assess fault current contributions, feeder impacts, and the effectiveness of anti-islanding protections to ensure grid safety and reliability.

Final determination of TT requirements will be made by HOL based on system conditions and protection coordination requirements.

Confirmation of DER disconnection is received at the HOL substation no more than one second after the trip signal is sent.

The Customer shall provide documentation, sealed by a Professional Engineer, confirming that all protections, including those substituting for TT, have been tested and comply with HOL requirements.

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8.2. Overcurrent Condition

Any element of the interconnection system external to DER yet, ahead of the PoC, should be installed in a fail-safe manner with self-checking features or redundant protection functions for large DERs.

Equipment and conductors shall be provided with overcurrent protection from each energy source. The DER protection system shall be capable of automatically isolating the DER from the Grid for the following:

- internal faults within the facility; and/or
- external faults within the Grid.

The protective device selectivity and sensitivity shall be maintained over the range of minimum to maximum fault currents with and without energy injection from the DER.

8.3. System voltage or frequency changes outside of limits

Over and under voltage, plus over and under frequency protection is required at the DER PoC.

The set points and clearing times for over or under voltages, plus over or under frequencies are dependent upon the magnitude of voltage and frequency variations and DER size as shown in IEEE 1547. DERs generating greater than 10 MW are required to follow voltage set points and clearing times specified by the IESO.

9. Monitoring and Control

HOL requires that all energy sources connected to the Grid that is in aggregate within a premise greater than 50 kW be monitored by HOL. For energy sources equal to or greater than 200 kW, the installation shall allow for HOL to disconnect the energy source from the Grid. These requirements ensure the safe and reliable operation of the Grid.

For DER installations with an aggregate capacity between 50 kW and 200 kW, where control functionality is not required, monitoring may be achieved through either a HOL Monitoring and Control Box (MCB) or an approved revenue-grade check meter capable of providing the required monitoring data to HOL. The selected monitoring solution shall meet HOL requirements for data accuracy, availability, and communication, and shall be subject to review and acceptance by HOL during the CIA process.

For DERs under 200kW, HOL may also require the use of monitoring and control equipment when the DER is connected to a HOL substation that has technical limitations. HOL will identify the need for and type of monitoring, or monitoring and control in the CIA.

HOL will provide its monitoring and control equipment at the Customer's cost. As a minimum, this equipment will monitor connection status, Real Power, Reactive Power, and voltage plus current per phase at the PoC.

For Medium and Large DERs, HOL will install equipment to integrate the DER with HOL's supervisory control system (SCADA) for continuous monitoring and control. The Customer must make provisions to enable the following minimum monitoring functions; depending on the Customer's DER application, HOL will provide detail and may define others through the interconnection process:

1. Status of all breakers or load break switches that parallel the DER to the Distribution System.

2. DER output voltage (per phase), current (per phase), power factor, frequency and harmonic distortion.

3. Provision shall be made by the Customer to have, on all synchronizing breakers, close coil circuits for the installation of a HOL "close-blocking" relay so that hold-offs (Block Enable) can be secured from the DER facility.

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4. Transfer Trip equipment, if needed for the project.

At the Customer's side of the PoC the monitoring equipment shall be inspected according to Rule 2-004 of the OESC and approved according to Rule 2-024 of the OESC.

The HOL monitoring and control equipment must be installed indoors.

10. Equipment Ratings and Requirements

The DER interface equipment shall be compatible with HOL equipment ratings at the connection voltage (maximum voltage, basic impulse limit, short circuit ratings, capacity etc.) and the incorporation of the added DER must not result in any Grid equipment operating beyond the Grid's operational rating. HOL shall review the equipment ratings for the purpose of assessing integration of the DER with the Distribution System. The equipment ratings to be reviewed include, but are not limited to, those discussed in this Section.

10.1. Equipment Thermal Loading

All of HOL's existing equipment in both distribution and transmission stations shall not be overloaded beyond acceptable limits under all operating conditions of the DER. This equipment includes feeder conductor, line voltage regulators, regulating stations, reclosers, circuit breakers and transformers.

HOL conducts a load flow study based on minimum system load conditions and maximum Customer generation, including all existing DERs already existing on the Customer's servicing feeder and station. The load (energy) flow study will identify the potential overload of the existing equipment.

10.2. Impact of DER Fault Contribution on Equipment Rating

The HOL Grid's interrupting devices shall be able to interrupt the maximum fault current that will flow through all devices. As such, all electrical equipment must be able to withstand the fault current passing through it for the required time so protection measures clear the fault.

The fault interrupting rating of the existing interrupting devices and the fault withstand rating of the electrical equipment shall be higher than the maximum fault current possible flowing through the equipment.

The addition of a DER will contribute to the total fault current on the existing Distribution System.
If the DER causes these limits to be exceeded, Distribution System equipment replacement or fault current limiting devices may be required.

10.3. Voltage Regulating

The HOL Grid has been designed for the unidirectional flow of power, from source (i.e., station) to the Customer. As such, the voltage regulating, metering devices and protection systems have traditionally been designed to correctly operate in these conditions. The connection of DER facilities to the distribution feeder could cause the power flow to be reversed through equipment and this could create difficulties with the equipment capability, including proper voltage regulation, energy measurement or protection operation.

Where the possibility exists for reverse flow through the existing voltage regulating devices and/or the metering points, incompatible equipment shall be replaced with those capable of bi-directional flow.

The direction of the power flow through voltage regulating devices connected between the DER and the transformer station shall be verified including line voltage regulators, regulating stations and transformers' under load tap changer, at the distribution station and transformer station.

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11. Revenue Metering

Bi-directional meters measuring energy delivered and energy received shall be installed by HOL. The cost of the installation will be the responsibility of the Customer.

All Embedded Generation 1 MW and above, requires IESO-approved metering installation. Metering installation for DERs below 1 MW shall be specified and supplied by HOL and shall meet the requirements of HOL standard GCS0008. The costs associated with the metering installation will be the responsibility of the Customer.

The Customer will provide a lockable/sealable enclosure space within an Indoor facility to install instrument transformers as required. This enclosure shall be readily accessible to HOL personnel.

Additionally, the Customer shall provide space for a HOL wall mounted metering enclosure. This space should be as close as possible to the location of the instrument transformers, if they are required.

12. Feeder Relay Direction

HOL's existing protections in the Grid are typically designed non-directional to clear faults occurring downstream from their location. When connecting a DER energy source, HOL shall review the existing protection to prevent unnecessary operation of upstream protection. This may require the replacement of non-directional relays with directional equivalents.

13. Additional Requirements

13.1. Connection Limitations

Based on the impacts of generation to short circuit levels, voltage deviations and operational issues, HOL has set connection limits to any circuit or substation in ECG0008.

13.2. Synchronizing Facilities

The generation connection must be supplied with adequate synchronizing facilities to properly operate and commission installation.

All breakers that are equipped with synchronizing abilities must include a means of showing synchronicity and are to include the following aspects in their design:

1. Synchronizing relay that has a visual indication on the front of the relay in the form of lights or light emitting diodes (LEDs) to indicate when the two voltages are in phase, AND
2. The synchronizing breaker cell shall be equipped with an analog or digital synchronizing scope ("Sync. Scope") with two lights that indicate the voltage across the synchronizing voltage transformers (bus and line).

   OR

   A digital display providing the information described in points one and two above.

If required, electrical or mechanical interlocks (e.g., a Kirk key) shall be used on load-break devices other than the synchronizing circuit breaker or contactor to ensure a non-synchronized DER cannot reconnect to the distribution system.

13.3. Remotely Operated DER Disconnecting Device Requirements

All circuit breakers or contactors used for remotely disconnecting the DER must be sized to adequately

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carry the DER rated full load current. Also, circuit breakers shall be rated to interrupt the total available fault current from the DER and the utility.

Circuit breakers shall be equipped with trip and close coils (maximum rated 125 VDC) and have sufficient auxiliary contacts (at least rated 125 VDC, 5 A) for Customer use and HOL use.

In the event that a circuit breaker is equipped with manual breaker operating control (example: pushbuttons on the front of the breaker), the manual “Close” function shall be physically disabled or removed.

13.4. DER Grid Support

Smart inverters shall, at a minimum, be UL 1741 SA certified. UL 1741 SA and SB certified inverters are preferred. Settings for grid support functions (e.g., voltage regulation, ride-through) will be specified by HOL as part of the CIA and commissioning process.

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Appendix A DER Hosting Capacity Calculation Methodology

When performing Distributed Energy Resource (DER) hosting capacity calculations, Hydro Ottawa considers all existing connected generators, as well as any DER projects with a valid Connection Impact Assessment (CIA).

Capacity screens are performed in a hierarchical manner across the transformer, bus, and feeder levels. A generation interconnection must pass each level of testing to proceed; failing a test upstream automatically means no test downstream will pass. Hydro Ottawa references the Upstream Hosting Capacity information provided by Hydro One to identify the upstream thermal and short-circuit limits for the relevant supply stations.

The maximum available generation capacity is based on the calculation that successfully passes the following tests:

1. **Thermal Tests:** Evaluates the capacity limits at both the Distribution Station and Transmission Station level to ensure reverse flow does not negatively impact the grid.

2. **Short Circuit Tests:** Evaluates limits at the Transmission Station bus level. The short circuit calculation must be adjusted based on the specific type of DER being connected:

    - **Synchronous and Induction Machines:** Assume a short circuit contribution of 5 times the generator's nameplate rating

    - **Inverter-Based Resources:** Assume a short circuit contribution of 1.2 times the generator's nameplate rating

Micro DERs are evaluated under a separate methodology that must ensure the total aggregated capacity of all Micro DERs does not exceed 50% of the minimum load on that specific feeder.

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