IESO Interim Requirements for the Application of IEEE 1547-2018

Requirements

The intent of these requirements is to maintain Bulk Electric System (BES) reliability in light of larger penetration levels of distributed energy resources (DERs). This document describes the IESO's interim requirements for the application of the Institute of Electrical and Electronics Engineers standard, IEEE 1547-2018. These requirements are applicable to DER projects receiving IESO support (financial, in-kind or other forms of support) where new, inverter-based equipment is to be installed. The IESO reserves the right to vary the application of these requirements in cases where such equipment was already purchased or installed prior to the time of the proponent's project support application to the IESO.

Requirements specified below may be in addition to requirements that are currently imposed by the local distribution company (LDC) in which the DERs reside, the Ontario Energy Board, *Distribution System Code*[1], and other applicable standards and best practices. These requirements may be superseded by any subsequent amendments to the *Distribution System Code,* the IESO market rules, CSA standards, or any regulatory instruments that may prescribe the specific application and use of IEEE 1547-2018.

Specific requirements for all applicable DER projects:

IESO REQUIREMENT: Each DER installation site shall use equipment designed and certified to be compliant with IEEE 1547-2018 once this standard is officially put into force by the Institute of Electrical and Electronics Engineers (IEEE). In the interim period until IEEE 1547-2018 is complete and in force, including the test procedures which are in draft form as of July, 2018, equipment meeting the following requirements set out in this document are acceptable

[1] OEB Distribution System Code: https://www.oeb.ca/oeb/_Documents/Regulatory/Distribution_System_Code.pdf.

IESO REQUIREMENT:

This section sets out requirements from DERs in the following topic areas:

1. Off-nominal frequency operation (remain connected between 59.4 Hz and 60.6 Hz)
2. Frequency disturbance ride-through shall be consistent with the off-nominal frequency curve in IESO Market Rules Chapter 4 Appendix 4.2.[2]
3. Voltage disturbance ride-through (IEEE 1547-2018 category III curve)
4. Frequency-watt control set to 4% droop and adjustable between 3% and 5%. The deadband shall not be wider than ±0.06%.
5. Avoid momentary cessation.
6. Voltage control strategy shall be coordinated with the LDC.
7. Reporting of static data
8. DER projects[3] 1 MW or greater must have real-time telemetry to the IESO of active power and state of charge (if applicable). Smaller projects must record data at a 5 minute resolution or better and send the data to IESO on a monthly basis.

IEEE 1547-2018 DER Categories

IEEE 1547-2018 separates DER requirements into three categories throughout the standard as follows:

1. **Category I** DERs are connected to an area with a low penetration of DERs and therefore would have less stringent requirements applied.
2. **Category II** DERs are connected to an area with a moderate penetration of DERs.
3. **Category III** DERs are connected to an area with a high penetration of DERs and have more stringent requirements applied, such as riding through more severe disturbances.

Table B.1 in Annex B of IEEE 1547-2018 provides an example of which category should apply to which resource type and application. Since Ontario has a significant amount of DERs already installed, category III requirements are recommended for all new DERs.

The application of category A or B, which determine the voltage control requirements, and the voltage control mode enabled shall be determined in coordination with the LDC.

IESO REQUIREMENT:

All IESO-funded DER pilot projects shall follow **category III** requirements.

Ride-Through Requirement

IEEE 1547-2018 defines the ride-through requirement based on applicable voltage, while IESO Market Manual 2.20 provides guidance on how to meet the requirement based on positive sequence voltage. Applicable voltage is defined in IEEE 1547-2018. The IESO is currently studying whether the IEEE 1547-2018 category II or III ride-through curves in meet system reliability needs for higher penetrations of DERs in Ontario. In the meantime IESO requires complying with the category III voltage ride-through curves. IEEE 1547-2018 ride-through curves are an input to the process of updating the CSA 22.3 No. 9 standard (*Interconnection of Distributed Resources and Electricity Supply Systems*), and it is presently unknown how closely the voltage ride-through requirements will be aligned. The CSA standard is expected to be finalized in 2018.

The voltage ride-through requirement for all three categories IEEE 1547-2018 is less stringent than the requirement described in Market Manual 2 Part 2.20 Figure 6, which was not necessarily designed to apply to all distribution connected facilities. Ideally the new voltage ride-through requirement will align with category 3 in Market Rules Chapter 4 Appendix 4.2:

> "Ride through routine switching events and design criteria contingencies assuming standard fault detection, auxiliary relaying, communication, and rated breaker interrupting times unless disconnected by configuration."

Frequency ride-through requirements in IEEE 1547-2018 for all three categories are more stringent than the IESO Market Rules Chapter 4 Appendix 4.2 off-nominal frequency requirement.

IESO REQUIREMENTS:

Voltage ride-through:

All IESO-funded DER pilot project proponents shall comply with the IEEE 1547-2018 category III voltage ride-through requirement.

Frequency ride-through:

All IESO-funded DER pilot project proponents shall comply with the frequency ride-through requirement in Market Rules Chapter 4 Appendix 4.2:

> "Operate continuously between 59.4 Hz and 60.6 Hz and for a limited period of time in the region above straight lines on a log-linear scale defined by the points (0.0 s, 57.0 Hz), (3.3 s, 57.0 Hz), and (300 s, 59.0 Hz)."

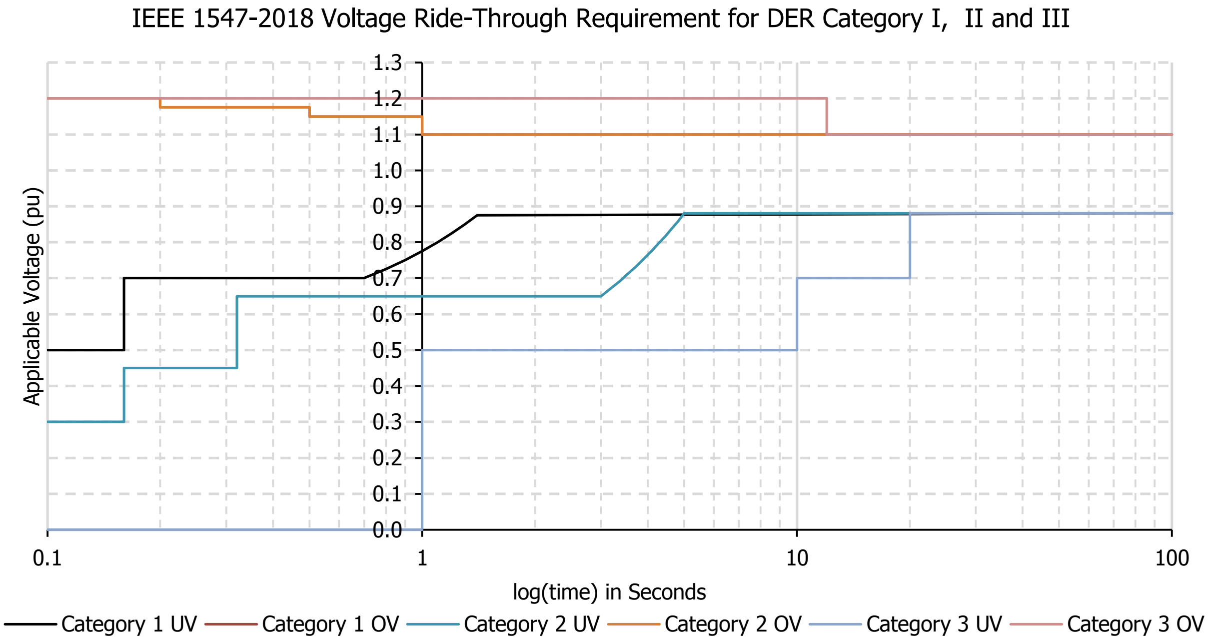

Figure 1: IEEE 1547-2018 voltage ride-through

Frequency-Watt Requirement

Active power shall be regulated with an average droop based on maximum active power adjustable between 3% and 5% and set at 4% unless otherwise specified by the IESO. Regulation deadband shall not be wider than ±0.06%. This type of control is equivalent to frequency droop control for conventional machines.

For example, if the power command based on nominal frequency is 1 MW, the rated active power of the facility is 10 MW, and the measured frequency is 59.7 Hz, the power command shall be increased by (10 MW)(60 Hz – 59.7 Hz)/(60 Hz * 4%) = 1.25 MW to a new power command of 2.25 MW. Facility ratings or lack of fuel (including solar insolation and wind) may inhibit the response.

Momentary Cessation

Momentary cessation is the automatic reduction of current output in response to a voltage or frequency disturbance. Once the voltage or frequency recovers the current output automatically returns to the pre-event value after a short delay up to 5 minutes. The Blue Cut fire and Canyon 2 fire events in California have raised the profile of the need to reduce the impact of or eliminate using momentary cessation as a response to events on the transmission system.

For category III DERs, IEEE 1547-2018 allows momentary cessation when the voltage is between 1.1 pu and 1.2 pu, and when the voltage is below 0.5 pu. The NERC Inverter-Based Resource Performance Task Force (IRPTF) has recommended[5] to not use momentary cessation since it poses a risk to bulk system reliability. Many DERs installed in 2018 or before implement momentary cessation for voltage dips below 0.9 pu, which would cause system reliability concerns at high penetrations of DERs.

IESO REQUIREMENT:

For category III DERs, momentary cessation shall not be utilized when the voltage is between 0.5 pu and 1.1 pu. Where using momentary cessation is unavoidable, current shall be restored without intentional delay in accordance with IEEE 1547-2018:

> "Shall restore output of active current to at least 80% of pre-disturbance active current level within 0.4 seconds."

Reconnection Time

Following momentary cessation or automatic disconnection of a DER, the possible options for reconnecting include manually, immediately once the voltage is healthy, or after an intentional delay. If the DER is connected to an intact grid (i.e., the DER is not in an electrical island), the DER should reconnect in no more than 5 seconds. From a transmission system level perspective, it is better for DERs to reconnect immediately once the voltage is healthy; however, this requirement could interfere with distribution system protections. Further analysis is needed to determine the impact on BES reliability for longer reconnection times at high penetrations of DERs.

Voltage Controls

Steady-state voltage controls:

It is expected that the need for different voltage controls will be determined on a local area basis. Areas with high penetrations of DERs will need more reactive support devices, which can be achieved in several different ways. Applying a requirement for DERs to provide voltage control may reduce the need for additional investments required to maintain local system reliability. Volt-var, volt-watt, and watt-var capabilities are required by IEEE 1547-2018, and deciding which, if any, feature to use should be done on a local area basis when determining the connection requirements of each project.

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[5] IRPTF, "Resource Loss Protection Criteria Assessment", February 2018, https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/IRPTF_RLPC_Assessment.pdf

Dynamic voltage controls:

Without additional investments in fast responding voltage control devices (e.g., SVCs or synchronous condensers), the grid is less resilient to transient disturbances as DER penetrations increase; DERs without fast-acting (less than 1.5 seconds) reactive power response are displacing generation with fast-acting response. Further study is needed to determine the DER penetration in Ontario that will require additional dynamic voltage support investments. Keep in mind that the location of DER and the contingencies that are respected greatly affect the need for these investments. Protections at the distribution system level are also affected by whether or not DERs provide dynamic voltage support.

IEEE 1547-2018 allows DERs to implement dynamic voltage support if it is under a mutual agreement with the area electric power system (EPS) operator. There is a possibility that requiring all DERs to provide dynamic voltage support would solve some system level dynamic voltage response concerns for systems with high DER penetrations, but protections at the distribution system level need to take the dynamic response into account.

IESO REQUIREMENT:

For category III DERs, the pilot project proponent shall demonstrate to the IESO that they have raised this issue with the host local distribution company and will provide the level dynamic voltage response specified by that LDC.

Reporting

To make informed planning and operating decisions, IESO needs to be aware of which DER voltage controls are implemented in the field aggregated by transformer station. The IESO is currently considering requirements whereby LDCs would be required to send IESO the total nameplate capacity of DERs at each transformer station that uses fixed power factor, fixed reactive power, volt-var, volt-watt, watt-var, and dynamic voltage support capabilities. Additionally, the voltage and frequency ride-through protection settings shall be sent to IESO. These reports should be sent on an annual basis.

IESO REQUIREMENT:

All DER pilot project proponents shall report to the IESO the total nameplate capacity of DERs at each transformer station that uses fixed power factor, fixed reactive power, volt-var, volt-watt, watt-var, and dynamic voltage support capabilities. Additionally, the voltage and frequency ride-through settings shall be sent to IESO.

Visibility

The IESO forecasts demand in timeframes ranging from near real-time to multiple years. Forecast error has a large impact on the economic operation of the grid as it can result in procuring extra resources in the long-term or committing extra resources in the short-term.

IESO REQUIREMENT: To reduce forecast error contributions, DER projects sized at 1 MW or greater must have real-time telemetry to the IESO of active power and state of charge (if applicable). Project size should be aggregated at a distribution station (DS) level or transformer station level if supplied directly from a transformer station when applying this requirement. For example, a 2.5 MW virtual power plant with 2 MW supplied by the first DS and 0.5 MW supplied by the second DS needs real-time telemetry to the IESO for the portion downstream of First DS.

Appendix A: Context and Background

In December, 2017, the North American Electric Reliability Corporation (NERC) published a report regarding a 2016 incident in the state of California in which approximately 1200 MW of solar DER capacity tripped due to a minor disturbance in the Bulk Electric System (BES).[7] The NERC report made recommendations regarding the importance of inverter settings and momentary cessation requirements in light of that serious reliability event on the BES in California. The IESO takes these observations very seriously, particularly given that the province of Ontario has the second highest penetration of small-scale solar capacity out of all of the sub-national jurisdictions in the North America.[8]

One of IESO's primary accountabilities is to maintain BES reliability. A decade ago DERs were not a major concern for BES reliability because of their relatively small level of deployment. At the time, many rules and standards across the electric utility industry were designed with the assumption that DERs would not have an impact on reliability of the transmission and distribution systems. Increasing penetrations of DER affected electric distribution utilities first, and now they are starting to affect Reliability Coordinators at the transmission system level.

As of December 31, 2017, the contracted installed capacity of already commissioned distributed generation was 3,301 MW with another 634 MW under development.[9] The highest DER penetration (DER Output / Ontario Demand) in Ontario was above 15% in 2017.[10] During the system peak in the summer DER penetration in Ontario is roughly 6%. Figure 2 shows the growth of DERs in Ontario in the previous three years.

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[7] North American Electric Reliability Corporation, "1,200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report, Southern California 8/16/2016 Event", June, 2017

[8] Source: U.S. Energy Information Administration, Electric Power Monthly: Table 6.2B Net Summer Capacity Using Primarily Renewable Energy Sources by State, and IESO data

[9] IESO Active Generation Contract List, http://www.ieso.ca/-/media/files/ieso/document-library/power-data/supply/ieso-active-contracted-generation-list.xlsx?la=en

[10] On Saturday May 20, 2017 Ontario demand was 11,722 MW in the middle of the day when output from solar farms was highest. At this time about 94% of visible installed embedded solar capacity and 35% of visible installed embedded wind capacity were generating; 1907 MW of embedded solar plus 207 MW of embedded wind is 2114 MW of embedded wind and solar. 2114/(11,722+2114) = 15%. Another 682 MW of other DER capacity (i.e., DERs that are not wind or solar) may have been online, but hourly data is not available and is difficult to estimate.

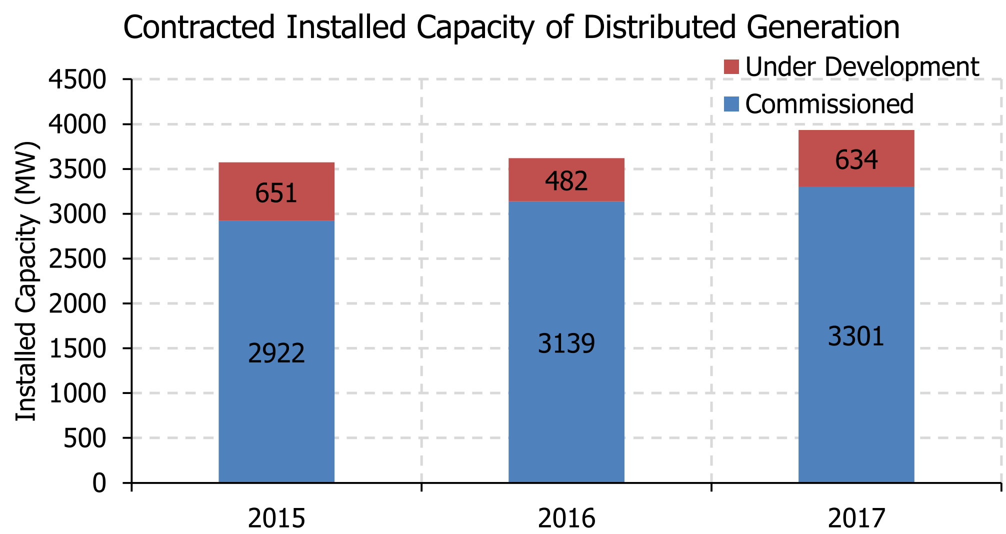

Figure 2: Contracted Installed Capacity of Distributed Generation[11]

Events that correlate DER behaviour over wide geographic areas are of particular importance to maintaining BES reliability. Since the frequency is the same across the interconnection, DERs should be required to remain connected during and after frequency disturbances. Voltage disturbances are typically local; however, faults at low impedance areas on the high voltage transmission system can drop voltages by 50% or more at large numbers of distribution stations. Figure **3** shows the voltage profile during a fault at a transmission bus.

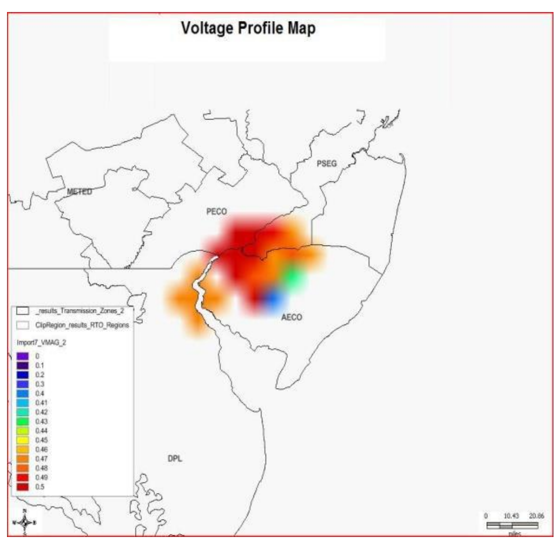

Figure 3**: Simulated Voltage Profile during a Fault at a Transmission Bus**[12]

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[11] IESO Active Generation Contracts List, http://www.ieso.ca/power-data/supply-overview/transmission-connected-generation

[12] IVGTF, "Performance of Distributed Energy Resources during and after System Disturbance," December 2013, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/IVGTF17_PC_FinalDraft_December_clean.pdf