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September 16, 2019

**SUBMITTED VIA ELECTRONIC MAIL TO BOARDSEC@OEB.CA**

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board 2300 Yonge Street
27th Floor
Toronto, Ontario
M4P 1E4

**Re: DER Connections Review – EB-2019-0207**

Dear Ms. Walli:

Advanced Energy Management Alliance ("AEMA") welcomes the opportunity to provide you with comments relating to the DER Connections Review – EB-2019-0207. AEMA is a North American trade association whose members include distributed energy resources ("DER"), demand response ("DR"), and advanced energy management service and technology providers, as well as some of Ontario's largest consumer resources, who support advanced energy management solutions due to the electricity cost savings those solutions provide to their businesses. These comments represent the views of AEMA as an organization, not any individual company, except as noted below.

AEMA agrees with the Ontario Energy Board ("OEB") on the high-level set of issues identified that are creating barriers to DER adoption, namely, standardization and consistency in the application of the rules; costs related to DER adoption; clear approvals timelines; and standardization of connection technical requirements. It is critical to AEMA members that processes provide certainty and predictability. Certainty and predictability could lead to reduced project development timelines and lower costs that translate into customer bill savings.

Regarding the questions posed in the OEB letter dated August 13, we provide the following feedback:

1) **Are the objectives for the DER Connections Review initiative clear?**

The objectives of the DER Connections Review are clear. Specifically, AEMA supports developing prescriptive technical requirements, with clear cost and connection process timelines for behind-the-meter ("BTM"), non-exporting energy projects that are consistent across all Ontario LDCs. Attached, you will find a submission made by Enel X, "Application Process and Technical Requirement Review for Behind-the-Meter Inverter Based Non-Export Battery Installations in Ontario", developed by Hatch Engineering, which provides a review of provincial and national technical requirements against Ontario policies.

It should also be acknowledged that AEMA members have been working through the Ontario Energy Association with utilities (DER Working Group) to identify short term actions that could be taken immediately that will not require amendments to the Distribution System Code ("DSC") and would deliver on the goal of faster approval time frames. Therefore, AEMA recommends that the OEB recognize this work and facilitate the adoption of these actions.

**2) Have staff identified the right topics for the DER Connections Review and do stakeholders have any specific concerns that they want to identify?**

At a high level, the OEB has identified the right topics. In addition to the articulated topics, we recommend that the following issues be addressed:

**i) Long DER Interconnect Process Duration and Timeline Uncertainty:** The DER interconnect process is unnecessarily long and uncertain even for simple non-exporting battery energy storage projects.

**ii) Additional Utility Metering for Gross Load Billing ("GLB") or Reserve Capacity Charge:** Is this really needed for customer owned, BTM, non-export energy projects which acts both a load and generator? The Ontario electrical code requires isolation breakers on either side of new utility meter measuring DER output which adds significant cost to the small and medium sized BTM, non-exporting energy projects.

**iii) Utility/Hydro One Monitoring and Control:** It is important that all parties understand this requirement and AEMA recommends education on why this is required for BTM, non-exporting energy projects.

**iv) Prescriptive Protection Philosophy and Elements:** Currently, new protection philosophy and approvals must be developed for each BTM, non-exporting energy project creating timeline delays and increasing costs.

**v) Consistency and Standardization on Transfer Trip Requirements:** Implementing transfer trip feeder protection can be cost prohibitive for small and medium sized BTM, non-exporting energy projects. Technical advancements in battery inverter anti-islanding capabilities and more cost-effective solutions to feeder grid protection are available and should be considered as viable alternatives.

**vi) Interconnect Cost Consistency and Predictability:** Total connection costs for BTM, non-exporting energy projects are a significant portion of the total capital costs, which are typically not established until the connection process is complete. Customers and developers must make considerable investments in Connection Impact Assessment ("CIA") application and Connection Cost Agreement ("CCA") application fees, then only receive Hydro One estimates for connection costs that are only committed to + 50% accuracy. An additional $30,000 can be invested in a Connection Cost Estimate to improve this accuracy to -20% to +30%. This cost uncertainty until the project is completed and capital invested makes investing in BTM, non-exporting energy projects financially difficult and risky for Ontario customers.

**vii) Standardization of Maximum Energy Storage System Size:** Individual LDCs have established policies for the maximum size (kW) that are allowed based on the average annual load. This limits the economic return of the systems without providing any additional benefits for the reliability or safety of the grid.
**viii) Standardize DER Interconnect Application Forms:** Each Ontario utility has their own Pre-Feed-in-Tariff ("FIT") Consultation Application (Form A), CIA Application and CCA application form. Most of the forms were developed to support solar projects and do not apply to BTM non-exporting energy projects. Delays and unwarranted cost are caused by confusion on what is required information on these forms for energy storage projects.

**3) Are there any proposed solutions that stakeholders wish to identify at this point?**
**i) Long DER Interconnect Process Duration and Timeline Uncertainty:** Implementation of a fast-track approval process for low risk projects. Attached, you will find a submission made by Stem Energy, which provides an overview of the California's Rule 21 approach and recommends a fast track approach for Ontario. Together with Local Distribution Companies ("LDCs") AEMA members can identify characteristics of BTM, non-exporting energy projects that can be granted interconnect approval using prescriptive requirements after thermal and short-circuit load capacity are confirmed. This would remove low risk projects from the queue and allow utilities to focus on complex projects that pose a higher risk.

**ii) Additional Utility Metering for Gross Load Billing (GLB) or Reserve Capacity Charge:** Establish a reasonable and consistent kW threshold across all Utilities (current threshold ranges from 100kW to 2MW depending on LDC) for GLB and associated metering costs for BTM, non-exporting energy projects.

**iii) Utility/Hydro One Monitoring and Control:** Establish a prescribed system size (kW) when monitoring and control are required for BTM, non-exporting energy projects. When necessary establish a prescribed set of monitoring points and develop a consistent approach to breaker position monitoring/control across all Ontario LDCs.

**iv) Prescriptive Protection Philosophy and Elements:** Establish a prescribed set of protection elements for BTM, non-exporting energy projects.

**v) Consistency and Standardization on Transfer Trip Requirements**: In response to Hydro One's review of the Technical Interconnection Requirements ("TIR"), AEMA made the attached submission. While we are uncertain of the outcome of the Hydro One review, AEMA members recommend that OEB facilitate the implementation of future improvements across all LDCs to ensure consistency of application.

**vi) Interconnect Cost Consistency and Predictability:** Establishing and standardizing prescriptive requirements for BTM, non-exporting energy projects including metering and transfer trip requirements when required. This will result in project costs becoming more predictable and consistent across the LDCs.

**vii) Standardization of Maximum Energy Storage System Size:** Policies on system sizes should be consistent across the province. Once capacity has been confirmed by the utility, there should be no artificial limit placed on system size for BTM, non-exporting energy projects.

**viii) Standardize DER Interconnect Application Forms:** Standardize the forms with clear direction on what information is required based on the size and DER technology.

**4) What is the best approach for development of solutions to the issues identified?**

Given that the issues outlined above relate either to process improvements or technical requirements, AEMA members recommend that the OEB create working groups under both these streams. Recommendations from these working groups would flow through to a regulatory working group to determine the need for DSC amendments or the use of other vehicles (such as bulletins, education opportunities, technical conferences, etc.) available to the OEB. AEMA also recommends that the Ministry of Energy, Mines, Northern Development, Independent Electricity Systems Operator ("IESO"), Electricity Safety Association ("ESA") and other relevant parties also participate in these discussions to ensure that the blind spots are reduced and agreed upon changes are implemented with minimal delay and confusion.

The ongoing reform process for California's Rule 21 interconnection regulation provides a useful example for structuring such proceedings. The California Public Utilities Commission ("CPUC") first gathered a list of over thirty major issues that were deemed in scope for the proceeding. These issues ranged from process streamlining and telemetry requirements to cost allocation and smart inverter functions. The issues were then grouped by related topics and ordered by urgency and degree of effort involved in resolution. Rule 21 stakeholder working groups were then created and scheduled to tackle groups of issues and given specific timelines for issuing recommendations on each issue.

Note that one of the key elements of working group operations was assigning an independent third-party facilitator that was not a utility, interconnection proponent or government agency. The successful facilitators have been organizations deeply experienced in the energy sector but also very well versed in facilitation of multi-stakeholder conversations. Other Commission-created working groups that tried to use Commission-staff or traditional energy policy consultants fared much more poorly. Furthermore, the CPUC created two additional interconnection working groups. The Smart Inverter Working Group ("SIWG") addressed deeply technical requirements for inverters deployed in California as well as the standards and certification rules for smart inverter functions and communications. The Interconnection Discussion Forum has become a monthly space for discussion of practical process issues that don't necessarily require changes to the regulations.

AEMA recommends that the OEB create such a Forum/WG to discuss "low hanging fruit" improvements to interconnection in the province and potentially implement changes more quickly than formal changes to the DSC. In doing so, the OEB can ensure the progress made by the Ontario Energy Association ("OEA") this year in the DER Working Group is converted into meaningful improvements across the province in the near term. The OEA effort has resulted in consensus for improvement in some areas among the participating stakeholders and the final report should be taken forward by an OEB led effort.

AEMA appreciates the opportunity to provide this feedback and AEMA members welcome the opportunity to participate in future working groups that may be established. Thank you for the consideration.

Best regards,

Katherine Hamilton

Katherine Hamilton
Executive Director
Advanced Energy Management Alliance

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Attachments:
Technical Information Requirements Submission
Stem Paper
Hatch Paper

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SUBMITTED VIA ELECTRONIC MAIL

July 31, 2019

Hydro One, Inc.

**RE: Proposed changes to Hydro One's Distributed Generation Technical Interconnection Requirements Interconnections at Voltages 50kV and Below, Rev3 document**

Advanced Energy Management Alliance ("AEMA") submits this letter in response to Hydro One's request for recommended changes to the referenced Technical Interconnect Requirements ("TIR") document. These proposed changes specifically target reducing installation timelines and improving cost effectiveness for the interconnection of battery energy storage, non-exporting, load displacement systems without compromising the safety, reliability and efficiency of Hydro One's distribution system. These proposed changes reflect updated standards and practices in the behind-the-meter energy storage industry in North America. In particular, many of these recommendations are based on new requirements and testing standards introduced by *IEEE 1547-2018, IEEE Standard for Interconnection of Distributed Energy Resources with Associated Electrical Power System Interfaces* and UL 1741 SA, Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources.

AEMA members are providers, supporters, and consumers of distributed energy resources, including demand response and advanced energy management, united to overcome barriers to the use of demand-side resources. Our mission is to advocate for policies that empower and compensate customers appropriately--to contribute energy or energy-related services or to manage their energy usage--in a manner that contributes to a more efficient, cost-effective, resilient, reliable, and environmentally sustainable grid. AEMA advocates policies that empower and compensate customers to manage their energy usage and make the electric grid more efficient, more reliable, more environmentally friendly, and less expensive. These comments reflect the views of AEMA as an organization rather than those of any particular member of AEMA.

In Ontario, the Global Adjustment ("GA") is the billing mechanism by which certain electricity supply costs are recovered from electricity ratepayers. "The global adjustment (GA) is the component that covers the cost of building new electricity infrastructure in the province, maintaining existing resources, as well as providing conservation and demand management programs."[1]

In 2011, the Government of Ontario introduced a policy known as the Industrial Conservation Initiative ("ICI"), which changed the way in which Global Adjustment costs are allocated to different classes of consumers. The stated purpose of the ICI is to provide large consumers with an incentive to reduce consumption during critical peak demand times.

Many economically important Ontario commercial and industrial customers do not have the ability to voluntarily reduce loads during Ontario electrical system peaks. Stopping the production lines or processes to reduce electrical costs at predicted system peaks is not economically feasible. These Hydro One customers are increasingly turning to battery energy storage systems to reduce electrical costs and remain competitive in the Canadian and global markets. In addition, these customers can now participate in Independent Electricity System Operator ("IESO") demand response programs for the first time, providing additional financial benefit to the customer and increased reliability of the grid during peak demand periods in Ontario. These program opportunities along with the recent cost reductions in battery technology have significantly increased the number of customers interested in connecting new energy storage systems to the Ontario grid; that interest is fully expected to continue to grow rapidly.

Because these energy storage systems are connected "behind the meter" ("BTM") and do not export power into the electrical distribution system, their impact to the reliability and safety of the grid is minimal and much less than distributed generation sources that export power into the distributors' electric power system ("EPS"). The Ontario Energy Board ("OEB") has recognized the reduced impact of BTM, load displacement (non-exporting) energy storage systems to the Ontario grid in at least one instance by exempting these systems from generator licensing requirements and distributor connection agreements.[2]

## AEMA TECHNICAL RECOMMENDATIONS

AEMA's recommended technical changes to the current TIR are summarized in Table 1. These changes would apply to battery energy storage, inverter-based facilities that fall under the "load displacement" definition in OEB's Distribution System Code, "a generation facility that is connected on the customer side of a connection point, that the output of the generation facility is used or intended to be used exclusively for the customer's own consumption."[3]

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[1] IESO Website http://www.ieso.ca/power-data/price-overview/global-adjustment

[2] OEB, Distribution System Code, 3/14/19: 6.2.1 Section: 6.2 Does not apply to connection or operation of an emergency backup generation facility <u>or an embedded generation facility that is used exclusively for load displacement purposes at all times</u>.)
(OEB, 6.2 Responsibility to Generators [6.2.2 Connection Agreements]

[3] This indicates that the facility is non-exporting.

**Table 1: Summary of Proposed Changes to Hydro One TIR**

| | **DG Class** | | | |
|---|---|---|---|---|
| | **Class 1: 0 kW < DG Facility Rating ≤ 250 kW** | **Class 2: 250 kW < DG Facility Rating < 1.5 MW** | **Class 3: 1.5 MW ≤ DG Facility Rating ≤ 10 MW** | **Class 4: DG Facility Rating > 10 MW** |
| **ANTI-ISLANDING PROTECTION** (TIR Section 2.3.12) | ESS conforms to UL 1741 SA | | | |
| **FEEDER PROTECTION RELAY** | Not required | Real time monitoring at POC with a protection relay to detect reverse power flow (32R). Shunt trip to disconnect the DG at the PCC. | | |
| **TRANSFER TRIP** (TIR Section 2.3.13) | Not required | | | A Transfer Trip (TT) signal from the station feeder breaker(s) to the DG Facility. |
| **CONTROL FACILITIES** (TIR Section 2.5.2) | DG Owner Control Only | | | DG Owner Control except remote disconnect of DG by contactor or shunt trip on DG at POC by Hydro One (eliminates requirement for motorized breaker) |
| **OPERATING DATA, TELEMETRY AND MONITORING** (TIR Section 2.5.3) | No requirement to install the SCADA link and modem | 1. Net active power (MW) output and reactive power (MVAR) flow and direction for each unit or total for the DG Facility<br>2. Phase to phase voltages for three-phase generators at PCC<br>3. Three phase currents on DG output<br>4. Connection status of generating units | | |

**<u>Anti-Islanding Protection</u>**
**Recommendation:** Require UL 1741 SA certification for all inverters utilized in BTM storage systems.

**Background**: An electric island is a section of the distribution system that, when disconnected from the rest of the Hydro One system, remains energized by the Distributed Generation ("DG") Facilities connected to the feeders. At the present time, Hydro One will not allow islanded operation. Anti-Islanding protection is required to:

- Ensure that Hydro One customers do not experience power cycle problems

- Prevent out-of-phase reclosing between Hydro One's distribution system and the DG Facility
- Reduce the risks of safety hazards caused by islanding; and
- Add redundancy to other protections

(Hydro One TIR Anti-islanding background)

**Current TIR Anti-Islanding Requirements**:
2.3.12 Anti-Islanding Protection

i. Upon loss of voltage in one or more phases of Hydro One's Distribution System, the DG Facility shall automatically disconnect from Hydro One's Distribution System within 500ms.
ii. The DG Owner shall demonstrate to Hydro One that it shall not sustain an island for longer than the time requirements in item (i) above
iii. All DG Facilities shall have anti-islanding protection. This may involve different protection functions; however, all DG Facilities shall have:
    a. Under/Over Frequency protection (Section 2.3.10);
    b. Under/Over Voltage protection (Section 2.3.11); and
    c. Transfer Trip for anti-islanding may be required as stipulated in Section 2.3.13.
iv. DG Facilities ≤ 500kW shall be exempted from Item (iii)(c) above and allowed to install the following passive anti-islanding schemes in lieu of Transfer Trip as in interim protection until Hydro One standardizes on a Transfer Trip solution for DG Facilities ≤ 500kW.
    a. Rate of Change of Frequency (ROCOF); and
    b. Vector Surge or Reverse Reactive Power.

Note: in subsequent Hydro One Bulletin B-02-DT-10-015.R3 (1/14/16) the exemption in Item (iv) was changed to "where Hydro One determines that its connection will not results in an unacceptable risk of an island formation in its distribution system.

**Technical Justification for Proposed Change:**
There have been significant advances in anti-islanding performance requirements including test procedures with the release of UL 1741 SA Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources *IEEE 1547-2018, IEEE Standard for Interconnection of Distributed Energy Resources with Associated Electrical Power System Interfaces.* The existing TIR only requires Over/Under Voltage and Frequency protection, two passive anti-islanding methods. Today, inverters mostly use active anti-islanding or a combination of active and passive anti-islanding measures due to their smaller non-detection zone ("NDZ") and better performance compared with the passive anti-islanding algorithms alone.

The improvements in anti-islanding techniques were driven by the concern that the increased penetration of DGs in the distribution system and the introduction of smart inverter capabilities to support grid stability (L/HVRT, L/HFRT, etc.) would compromise existing anti-islanding techniques. Subsequent testing and reports show the more stringent requirements in these standards have improved inverter anti-islanding performance despite increased DG penetration.[4]

Two of the states with the highest DG penetration now require UL 1741 SA certification. The state of California requires DERs to comply with UL 1741 SA as of September 8th, 2017. Hawaii implemented UL 1741 SA configured with the 14H SRD in March of 2018. Since California is by far the largest market for energy storage in North America, energy storage system suppliers have been forced to make their inverters UL 1741 SA compliant.

**Reverse Power Protection Relay**

**Recommendation:** Real time monitoring at Point of Connection ("POC") with a protection relay to detect reverse power flow (32R). The protection relay monitors at the POC and controls a breaker through a shunt trip to disconnect the DG at the PCC.

**Background**: Hydro One's existing TIR does not reduce feeder protection requirements for BTM DGs used exclusively for load displacement because the document was written for DGs that export to the grid to generate revenue, like the Solar FIT program. A recent notable exception is Bulletin B-03-DT-10-015.R3 (6/24/19) that changed the maximum feeder limitations for DG generation to *exporting* three-phase generation.

**Current Reverse Power Protection Relay Requirements**:
No Reverse Power Protection Relay requirements in existing TIR.

**Technical Justification for Proposed Change:**
The addition of a reverse power protection relay will ensure that BTM energy storage system never exports power onto Hydro One's distribution system. In addition, the protection relay will now provide additional passive anti-islanding protection at the POC (inverter monitors at the PCC) including overvoltage (59), undervoltage (27), vector jump (78V), over frequency (81O), underfrequency (81U), and rate of change of frequency (81 ROCOF).

**Transfer Trip**

**Recommendation**: Transfer Trip protection is not required for systems below 10 MW aggregate capacity. If the TIR does establish a threshold lower than 10 MW, exceeding the threshold does not automatically require a transfer trip. Any project larger than the threshold

[4] NREL, Validating the Test Procedures Described in UL 1741 SA and IEEE P1547.1, May 2018.

but smaller than 10 MW would be analyzed in detail for viability of alternative solutions that have been proven successful in other jurisdictions.

**Current Transfer Trip Requirements:**
The current TIR requires Direct Transfer Trip for all DG facilities with aggregate capacity over 1MW.[5] The addition of transfer trip functionality to the feeder protection requirements can add $150-$400K of additional capital cost and significantly delay the commercial operation date to the project depending on the line-of-site distance from the feeder breaker or upstream recloser and the DG project site. For a smaller 1-2 MW BTM energy storage project, the addition of transfer trip protection can increase capital cost over 25% and make it no longer financially viable. Conversations with Hydro One staff have revealed that the 1 MW threshold is somewhat arbitrary, as there appears to be no specific technical justification for that number.

**Technical Justification for Proposed Change:**
For load displacement inverter-based facilities, industry best practices combined with UL1741 SA anti-islanding as well as the recommended reverse power relay requirements are sufficient to mitigate the grid risks addressed by direct transfer trip protection. Hundreds of such installations have been interconnected in other jurisdictions in North America without the installation of a transfer trip.

It has been expressed that a primary risk that justifies transfer trip is that an island could be formed and may still be present when the grid reclosers re-establish the grid power after a fault has occurred. The potential synchronization mismatch between an island and the re-formed grid can cause damage to equipment.

Other jurisdictions have addressed this risk in the following ways

- Anti-islanding functions in modern inverters prevent the formation of islands with a faster response time than the grid reclosers;
- Additional anti-islanding protection schemes;
- Reverse power relays prevent the export of power that would mismatch with the re-formed grid; and
- Settings on network re-closers are adjusted for longer response times, to exceed the response time of the anti-islanding functions.

<u>**Control Facilities**</u>
**Recommendation:** Eliminate requirement for Hydro One to assume control of BTM, non-exporting, load displacement battery energy storage systems for Class 1-3 facilities. When remote disconnect capabilities are required for Class 4 facilities, do not require a motorized breaker.

**Current Control Facilities Requirements**:

[5] TIR Section 2.3.13 i

Section 2.5.2 of the TIR provides Hydro One to have control over significant aspects of the DG facility "Subject to the agreement between the DG Owner and Hydro One".

**Technical Justification for Proposed Change:**
There is no technical reason for Hydro One to assume control of BTM, non-exporting, load displacement battery energy storage systems. When Hydro One requires the ability to remotely disconnect the DG system, eliminate the requirement for motorized breakers. Since there is no scenario for Hydro One to turn the system back on, a more cost-effective implementation is to disconnect with a shunt trip on the DG main breaker controlled through the SCADA system.

**<u>Operating Data, Telemetry and Monitoring</u>**
**Recommendation:** No requirement for SCADA system for Class 1 facilities. For facilities above 250kW, require real time data from BTM, non-exporting, load displacement DG facilities that would impact the reliability and safety of the Hydro One distribution system.

1. Net active power (MW) output and reactive power (MVAR) flow and direction for each unit or total for the DG Facility
2. Phase to phase voltages for three-phase generators at PCC
3. Three phase currents for each unit or total for the DG Facility
4. Connection status of generating units

**Current Control Facilities Requirements**:
Section 2.5.3 of the TIR provides Hydro One to have control over significant aspects of the DG facility "Subject to the agreement between the DG Owner and Hydro One".

**Technical Justification for Proposed Change:**
Prescriptive requirements for what is monitored, and which the monitoring points are required, allows engineering to be finalized early in the project to establish project costs and schedules.

## TECHNICAL NEXT STEPS

AEMA appreciates the opportunity to provide Hydro One input on the TIR to update requirements to reflect updated standards and best practices in the industry. AEMA suggests that a beneficial next step for Hydro One would be to host a technical conference where experts from Hydro One can raise the level of understanding of service providers, customers and distributors on the rationale for and the application of the various standards in the TIR.

## AEMA POLICY DISCUSSION

Hydro One Bulletin #B-03-DT-10-015.R3 (issued 6/24/19) defines non-exporting DG Facilities and acknowledges that some technical requirements for non-exporting DG Facilities should differ from DG Facilities that deliver power to the distribution grid. Specifically, it was previously unreasonable to subject non-exporting DG Facilities to a feeder current capacity limitation when such facilities did not add current to the feeder. The Bulletin corrected this issue by specifying that non-exporting DG Facilities are not subject to the feeder current limitations.

The same Bulletin, however, establishes that non-exporting DG Facilities are still subject to the power flow ("backfeed") thresholds at the Hydro One transmission or distribution substations. From a purely technical power flow perspective, the limitation is reasonable as the interconnection of a new non-exporting DG Facility can cause the combined generation at that substation to exceed the threshold. However, from a policy/legal perspective, holding the new non-exporting DG Facility responsible for costs incurred by the combined DG exceeding that threshold is clearly unreasonable.

AEMA recognizes that this is policy matter and that the TIR consultation purpose is to focus on technical improvements. AEMA recommends, however, that given the close connection between these issues that an opportunity be created to discuss issues that have direct impact on customer choice and applicability of DG Facility fees on a non-exporting DG Facility.

We appreciate the opportunity to provide these comments and report to you. We look forward to continuing this discussion. Should you have any questions, please do not hesitate to contact us at Katherine@aem-alliance.org or 202-524-8832.

Sincerely,

Katherine Hamilton
Executive Director
Advanced Energy Management Alliance

# Ontario Energy Storage System Interconnection Modernization


Reference #: EB -2018-0287

Submission on the “Report of the Advisory Committee on Innovation of the OEB”

January 25, 2019

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## 1. Executive Summary

Energy Storage Solutions (ESS) are a rapidly emerging technology that offers electricity consumers a cost-effective and flexible energy management option. ESS deployed as a load displacement resource can give customers control of their consumption profiles to reduce electricity costs along with meeting their electricity service needs.

The regulatory framework for the connection of ESS in Ontario restricts the deployment of load displacement ESS for electricity consumers in the province, specifically due to:

- Unpredictable treatment by Local Distribution Companies (LDCs);
- Lack of definition of energy storage resources or their treatment by LDCs in the Distribution System Code (DSC);
- Inconsistent application of the load displacement exclusion from the DSC; and
- Contradictions with the Conservation First Framework.

Based on Stem's robust experience in advanced energy storage for commercial and industrial facilities, ESS can offer significant advantages to Ontario electricity consumers. To unlock the full value of energy storage, Stem has the following recommendations for Ontario's regulatory framework with respect to connections to the grid:

1. Define a separate LDC responsibility for the treatment of energy storage in the DSC;
2. Require consistent treatment of load displacement resources across Ontario;
3. Establish an expediated connection process for load displacement resources;
4. Require LDCs to develop resources to aid siting of distributed energy resources in their service territory; and
5. Clarify connection cost responsibility for customer load reduction activities.

The recommendations will allow Ontario's electricity consumers to lower their electricity costs and serve their evolving energy needs to meet the challenges of the future.

## 2. Background

Over the past decade, the cost of ESS has fallen dramatically, with close to an 80% reduction of lithium-ion battery prices since 2010. It is estimated that almost 700 megawatt-hours of ESS has been deployed in the US in 2018 and the global ESS market could add almost 8 GWh in 2019. In the US, the energy storage market could more than double to $973 million in 2019 compared to an estimated $474 million in 2018 thanks in large part to government policy, regulation and electricity market design changes[1].

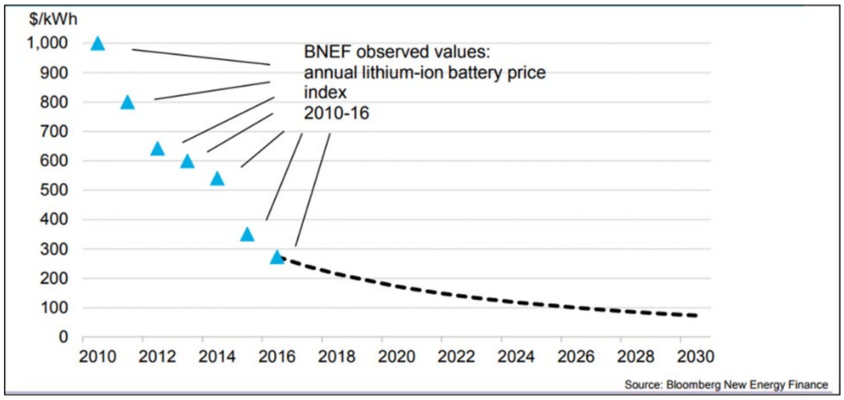



*Figure 1: Annual Lithium-Ion Battery Price Index -Source: Bloomberg New Energy Finance (BNEF)*

ESS offers a wide range of desirable characteristics to consumers including emergency back-up supply and power quality improvement. ESS deployed as load displacement resources (i.e., used to shift a customer's consumption from the electricity grid; also known as non-export embedded resources) can give electricity consumers unique capabilities to mitigate their electricity costs. In short, the emergence of cost-effective ESS has the potential to offer significant value for electricity consumers in Ontario.

## 3. Connection Issues for ESS

The ability of load displacement ESS to offer electricity cost mitigation among other benefits to large electricity consumers is hampered by the existing regulatory framework in Ontario. Specifically, connection issues unique to the Ontario electricity sector are restricting the ability of ESS to offer the full range of benefits from load displacement for consumers. The regulatory framework in Ontario includes legislation, regulation, codes (e.g., DSC), and rules that govern the electricity sector in Ontario including LDCs and the

[1] https://www.greentechmedia.com/articles/read/four-trends-to-watch-in-the-energy-transformation-of-2019?utm_medium=email&utm_source=GridEdge&utm_campaign=GTMGridEdge#gs.we5pN1Mr and https://www.greentechmedia.com/articles/read/five-predictions-for-the-global-energy-storage-market-in-2019#gs.XZs9jFoz for more information. See the U.S. *Energy Storage Monitor* report by Wood Mackenzie and the Energy Storage Association - https://www.woodmac.com/research/products/power-and-renewables/us-energy-storage-monitor/

regulator, i.e. the Ontario Energy Board (OEB). The following sub-sections list priority connection issues that are hindering the deployment of load displacement ESS for the benefit of customers.

### 3.1. Unpredictable treatment by LDCs

In Ontario, there are over sixty (60) LDCs with vastly different service territories and customer composition. Some service territories cover large rural areas with a couple thousand residential and small commercial customers. Other service territories are dense urban areas with well over 100,000 customers composed of industrial, large commercial and residential customers. The large number of LDCs has led to an uneven application of codes and rules for the treatment of ESS requesting connection to Ontario's distribution networks. For example, some system conditions can trigger costly protection & control (P&C) schemes (e.g., transfer trip) that halt or delay ESS projects in one LDC service territory, while similar system conditions do not trigger any costly system investments in another service territory. The unpredictable requirement for transfer trip is often the most significant cost burden and regulatory hurdle for ESS projects. Without consistent standards, it is difficult for ESS projects to avoid constrained areas of the distribution system or work with customers to deliver the energy services those customers desire. Further, the coordination between the connection LDCs (i.e., the LDC who owns the service territory where the ESS is proposing to connect to) and the upstream distributor or transmitter (e.g., the entity that owns the upstream substation) has not been transparent and has been at times contradictory. Responsibility for communication and coordination of connection activities between the two connection authorities in some instances has not been transparent, further delaying connection of load displacement ESS.

### 3.2. No definition of treatment for energy storage

The OEB's DSC defines the responsibilities for LDCs to load customers and to generators requesting connection to the distribution system; however, the code has no unique treatment for energy storage systems (ESS). As such, energy storage systems are pigeon-holed into processes that were designed for resources they are not well suited for. The unique characteristics and capabilities of energy storage are therefore not appropriately considered during the connection application process.

### 3.3. Application of load displacement exclusion in the DSC

While the DSC states responsibilities of LDCs to new generators either directly connected or behind-the-meter, there exists an exemption for resources that are solely for the purpose of load displacement (i.e., non-export behind-the-meter resources).

LDCs are expected to outline the load displacement connection processes within their Conditions of Service (i.e., standard terms and conditions for connection and operation on their distribution network). In practice, many LDCs provide little to no unique treatment for load displacement resources or energy storage. Instead, load displacement resources are treated as if they were a connection that will export energy to the distribution system despite the reduced impact to the operation of the distribution network compared to resources that inject energy into the grid. In some cases, the load displacement treatment assumes the behind-the-meter resource is only used for emergency service and not for broader customer value. The result is an overly restrictive connection capability assessment and burdensome protection & control costs that are unnecessary and ultimately restrict the capabilities of ESS sophisticated power electronic controls.

### 3.4. Contradiction to Conservation First Framework (CFF)

For load displacement resources, the application of exporting connection requirements contradicts the conservation first framework that exists in Ontario. Under existing legislation (CITE), the OEB and LDCs are supposed to encourage and incentivize conservation efforts that reduce demand from the grid. Load displacement resources are not appropriately being recognized as an effective conservation and demand management activity. Conservation from energy storage resources provides two benefits for rate-payers. First, energy storage can reduce consumption during high demand periods and second, energy storage can significantly increase the utilization of existing generation, transmission and distribution assets without straining the power system. Overall, the connection of load displacement ESS should be encouraged by LDCs and the OEB to support the CFF.

## 4. Proposed Recommendations

Rapid growth of energy storage installations has demonstrated the value to power systems and customers; however, barriers still exist that limit the potential of energy storage. In jurisdictions across North

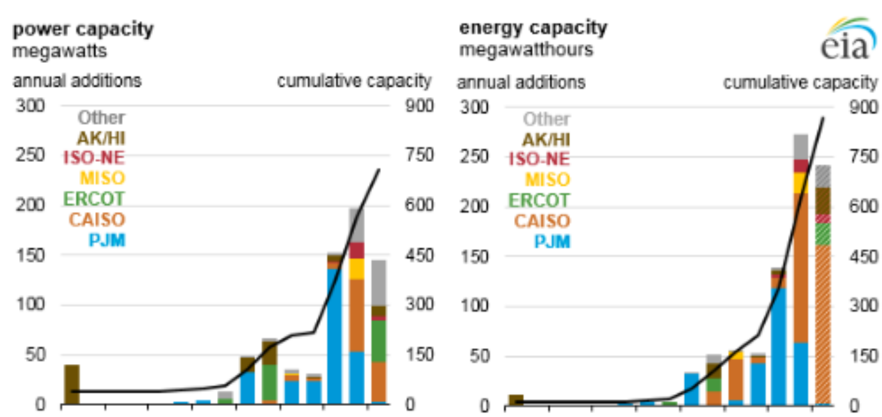



*Figure 2: Energy storage growth in the USA -Source: Energy Information Agency*

America, regulatory frameworks are being reviewed and updated to support the deployment of energy storage in a fair and efficient manner. Energy storage in Ontario faces both similar and unique challenges to offering their services to customers and providing additional value to the power system.

To assist in addressing these challenges, this paper proposes the following recommendations to assist in resolving connection issues for load displacement ESS.

### 4.1. Independent responsibility for energy storage in the DSC

The DSC outlines LDC's responsibilities to both load customers and generation customers.  While energy storage resources have the capability to act as either a load or a generator, they are unique and therefore should have unique treatment in Ontario's regulatory framework.  It is recommended that a new LDC responsibility to energy storage resources be created in the DSC that reflects energy storage's physical operating characteristics and attributes. The LDC responsibilities to energy storage should include response to connection request applications, requirements for a connection agreement, access to the energy storage site, and what conditions should be included in the LDC's Conditions of Service.  Further, the DSC should clarify what distribution system investments are appropriate to assign to energy storage resources during connection, and what distribution systems investments should be funded by distributors for the benefit of all distribution customers. In short, the DSC should be expanded to clearly state for LDCs and energy storage providers the expectations for engagement in Ontario.

### 4.2. Consistent treatment of load displacement resources

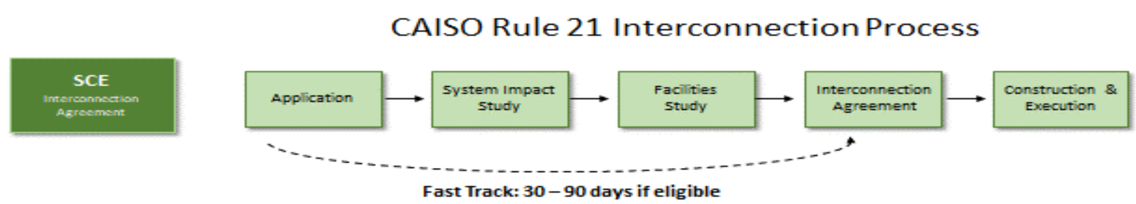
Section 6.2.1 states that LDC responsibilities to generators do not apply to generation used exclusively for load displacement purposes. In practice, the treatment of load displacement resources is described within each LDC's Conditions of Service.  Most Conditions of Service do not consider energy storage for load displacement purposes and have inconsistent treatment of load displacement resources in general.  Load displacement resources are an important tool for customers to manage electricity costs but the value they can provide is restricted without consistent treatment.  The DSC should address the primary requirements for treatment of load displacement resources, including energy storage. The requirements should describe the different treatment between a load displacement resource (i.e., a resource that does not export to the grid) and an embedded resource that may export to the grid including but not limited to the connection process, operating requirements and communication standards.

### 4.3. Establish an expediated connection process for load displacement resources

The impact on the distribution system differs for embedded resources that export and embedded resources that do not export (i.e., load displacement). Effectively, load displacement resources are similar to investing in energy efficiency to reduce consumption; therefore, the impact on the distribution system should be less than an embedded resource that may export to the distribution system[2]. Given the lower impact of load displacement, it is recommended that an expediated connection process for load displacement resources be established (see box at bottom with information on California's Electric Rule 21 Fast Track Application).

What is a Fast Track application?

The "Fast Track Application" is an application to participate in the Fast Track process for expedited interconnection. Fast Track is intended for projects up to 3MW (SCE) or 5MW (PG&E) for interconnection requests and allows an eligible facility to bypass some interconnection studies if it meets a series of "screens".




The expeditated connection process should include shorter timelines for Connection Impact Assessments (CIAs) and standard connection agreements, if applicable. There should be no capacity size restrictions since by definition load displacement resources are only offsetting existing load and will not export to the grid. The connection agreement should include standards and operating requirements that ensure load displacement resources will not under reasonable circumstances export energy to the grid.

[2] The proposed approach is similar to the California Rule 21 Interconnection. Electric Rule 21 is a tariff that describes the interconnection, operating and metering requirements for generation facilities to be connected to a utility's distribution system. The tariff provides customers wishing to install generating or storage facilities on their premises with access to the electric grid while protecting the safety and reliability of the distribution and transmission systems at the local and system levels. Generating facilities that do not export to the grid or sell any exports sent to the grid (Non-Export Generating Facilities) are not subject to CAISO Tariff.

It is recommended that within DSC Section 6 “Distributors’ Responsibilities”, a new subsection titled “Responsibilities to Load Displacement Resources” be adopted with the following proposed language:

- *This section applies to the connection of load displacement resources including all net energy metering facilities, "Non-Export" facilities, and qualifying facilities intending to sell power at avoided cost to the host utility.*
    - *“Non-export” facility means when a generator or energy storage facility is sized and designed such that the generator or energy storage facility output is used for host load only and is designed to prevent the transfer of electrical energy from the generator or energy storage facility to the Distribution system.*
- *This section does not apply to the connection of generation or energy storage facilities that intend to participate as Market Participants in the IESO-Administered Markets except for load displacement resources intending to become Demand Response Market Participants*
- *A distributor shall make every reasonable effort to respond promptly to a customer’s request for connection. In any event a distributor shall respond within 5 business days to a customer’s written request for a load displacement resource connection with a confirmation that the request is complete or a notice of additional information needed. A distributor shall complete an Expediated Connection Assessment (ECA) within 15 business days of the date when the request is confirmed complete.*
- *The distributor is responsible for posting their ECA process including a description of the connection assessment screens the ECA process will perform.*
- *If the load displacement resource passes the ECA, and there are no identified upgrades required for connection, the distributor will offer a connection agreement within fifteen (15) business days following the ECA results.*
- *If the load displacement resource passes the ECA, but there are identified upgrades required for connection, the distributor will deliver a cost estimate of such upgrades within fifteen (15) business days following the ECA results.*
- *If the load displacement resource does not pass the ECA, the distributor may hold a meeting with the customer to determine the next steps and recommended options for the load displacement resource, which may include conducting a Connection Impact Assessment.*

### 4.4. Require LDCs to develop resources to aid siting of distributed energy resources

The power system is a complex network that is difficult for external parties (e.g., ESS developers) to determine where connection locations face the lowest barriers to entry. Some locations in the power system may be constrained where even the connection of load displacement resources will potentially lead to distribution system issues. The current connection process does not provide any indication of these constrained areas until after a CIA is complete which is a waste of funds and effort. Instead, a proactive approach would be for LDCs to develop resources to aid siting of distribution energy resources. For example, the Massachusetts Department of Public Utilities (DPU) has ordered all public utilities (e.g., LDCs) to publish the following information to guide new connections:

- Monthly report summarizing the number of projects requesting connection by distribution feeder
- A feeder saturation map that shows the level of feeder saturation (i.e., oversubscribed) for each city/town in the LDC's service territory
- Service quality reports for each distribution feeder including feeder characteristics, line automation, rating information and interruption information

As part of the Feed-In Tariff (FIT) program, LDCs were expected to produce estimations of connection capability by distribution feeder and substation; therefore, a similar approach for load displacement should be completed by LDCs respecting the differences between load displacement and embedded exporting resources.

LDCs draft feasibility reports (e.g., Hydro One's Form A) that provide guidance to new connections. LDCs should at a minimum provide draft feasibility reports upon request by connection point that include the following information: (1) feeder voltage; (2) feeder name; (3) feeder rating (e.g., MW) (4) voltage at proposed location; (5) single- or three-phase service availability; (6) distance from three-phase service if only single-phase service is available; (7) aggregate installed capacity of embedded generation on a particular feeder; (8) aggregate pending capacity (submitted connection applications that are not yet connected) of embedded generation on a particular feeder; (9) whether the site is served by a radial network, secondary network, or spot network; (10) minimum load information on a feeder; (11) description of available feeders within 0.25 miles of the proposed location; and (12) other potential constraints or critical items that may jeopardize the project.

Where constraints exist, LDCs should identify and publish information on constrained areas. The information should include reasoning for the constraints and describe the steps being taken to address the system constraints. Specifically, one-off installations of transfer trip schemes to connect ESS may be a less cost-effective solution compared to alternative solutions that address the system constraint broadly and allow customers to realize the value of ESS without the cost burden of transfer trips.

### 4.5. Clarify connection cost responsibility for customer load reduction activities

Since in many cases constraints for load displacement can be exacerbated by energy efficiency activities, LDCs should be motivated to address load displacements constraints to support the CFF and ensures customers have the opportunity manage their energy costs. As a general rule (consistent across North America), a customer connecting a load displacement resource is not responsible for costs associated with addressing power flow or voltage constraints on the associated feeder or substation. The OEB in late 2018 issued amendments to the DSC (as well as the Transmission System Code (TSC)) related to cost responsibility rules for load customers under the principles of beneficiary pays[3]. As with energy efficiency, customers shouldn't be assessed costs on the grid for taking demand away and potentially reducing costs for other rate-payers. This rule should be formalised in the DSC to ensure consistent application across all LDCs.

[3] See OEB's Regional Planning and Cost Allocation Review (EB-2016-0003) - https://www.oeb.ca/industry/policy-initiatives-and-consultations/regional-planning-and-cost-allocation-review

Project Report

January 28, 2019

# EnerNOC Inc.

# EnerNOC Energy Storage Interconnection Assistance

# Application Process and Technical Requirement Review for Behind-the-Meter Inverter-Based Non-Export Battery Installations in Ontario

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## Notice to Reader

This report has been prepared by Hatch Ltd. (Hatch) for Enel X Inc. (the “Client”, formerly branded as EnerNOC) for assisting the Client with the analysis of application process and technical requirements for implementation of the behind-the-meter battery energy storage systems for deployment in Ontario.

This report contains opinions, conclusions and recommendations made by Hatch, using its professional judgment and reasonable care. Use of or the report or any information contained therein is subject to the following conditions:

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# 1. Introduction

Enel X Inc.[1] provides Behind-The-Meter (BTM) Lithium-Ion Battery Energy storage solutions to several customers in Ontario, where these solutions are offered to help reduce the Global Adjustment (GA) electricity costs of their facilities.

[1] Formerly branded as EnerNOC Inc.

Enel X has expressed concerns over the long processing times and certain technical requirements of Ontario LDCs for BTM energy storage interconnections. It is believed that the times and requirements are too conservative compared to requirements in other jurisdictions.

If the processing times for such applications are reduced, customers and developers can bring their systems on-line faster with greater economic benefit to customers. This will support the IESO GA charge objectives of reducing peak Ontario demand which can benefit Ontario.

Enel X also believes that the technical requirements for BTM non-export solutions for GA reduction should not be lumped in with the technical requirements of other types of distributed generation. Examples of other types could include solar PV farms that have their own connection point before the meter, or a synchronous generator type source which has a high short circuit current capability. Enel X includes software in their offering to address the issue of power export, through a Minimum Import Power (MIP) software feature.

Enel X has approached Hatch to conduct a study to analyse and compare the processing times and technical requirements for non-export BTM inverter-based battery energy storage systems in Ontario and compare with practices in selected other North American jurisdictions. The requested Hatch scope of work was performed in 2 parts: Part 1 study of the processing times, and Part 2: review of the technical requirements.

This report is the Hatch deliverable to Enel X for this project. In preparation of this report Hatch has used its in-house information, information results from discussions with Ontario LDCs, public domain information on similar processes and requirements in select other jurisdictions and information provided by Enel X.

# 2. Executive Summary

This report presents the results of the Parts 1 and 2 of the study including:

- Review of provincial and national regulations (OEB and FERC requirements)
- Comparison of technical requirements and application processing times for BTM Energy storage interconnection for several Ontario LDCs (Alectra, HONI and THES), and LDCs in other jurisdictions (California, Alberta and Texas)
- A technical analysis of the reasons for direct transfer trip and monitoring requirements including the latest version of IEEE 1547, and relevant published studies
- A review of Enel X BTM energy storage interconnection application processing times in Ontario
- Results of the discussions with a representative from Toronto Hydro

In most jurisdictions studied, the BTM energy storage applicant must follow the same procedure that is required for the distributed generator interconnection to the electric utility grids. In Ontario, the utilities generally follow the OEB DSC rules for all types of distributed generator applications. Most LDCs have stated their own processing time-lines.

The figure below shows a bar graph comparison of stated processing time for the various LDCs studied. However, it must be noted that the timelines are specific to key deliverables and do not cover potential delays related to correspondence or rework that may be required in the approval process. Correspondence turn-around times are not entirely clear throughout the application process for regulatory and LDCs but is generally found to be up to 15 days (e.g. information request, preliminary meeting, etc.).

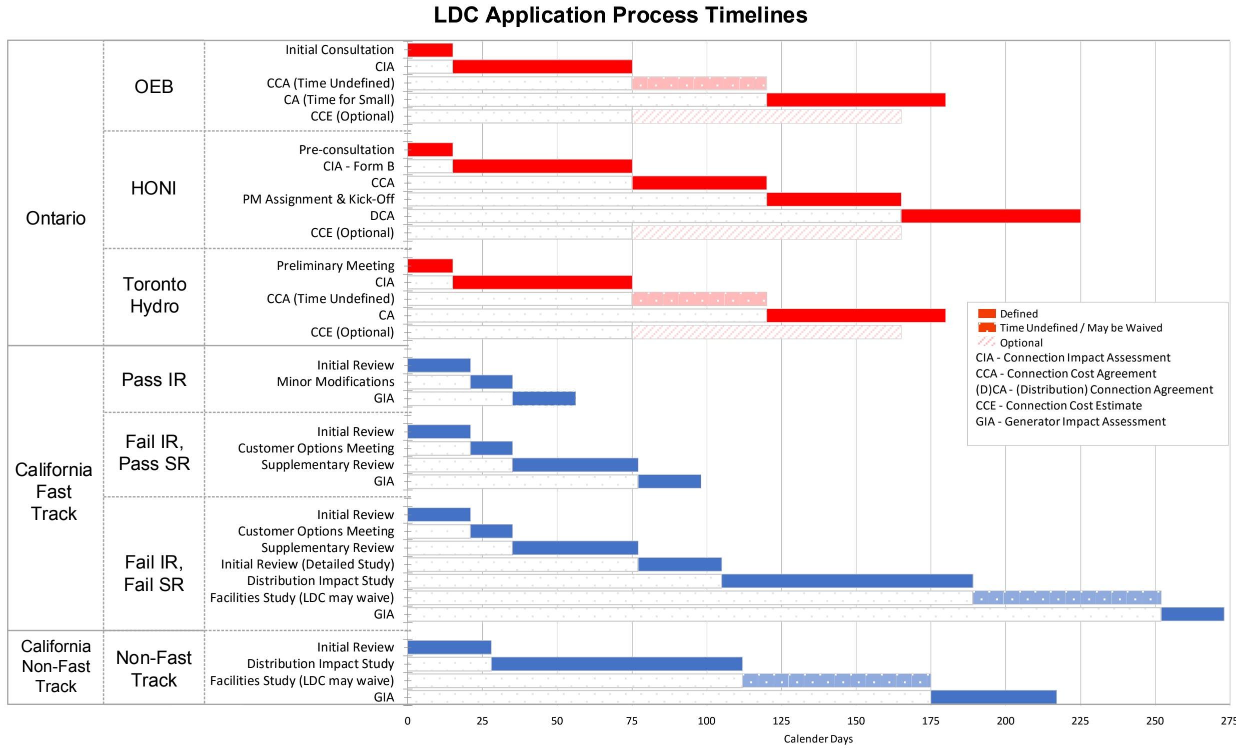


**Figure 2-1: LDC Application Process Timelines**

1. Timeline for California has been adjusted from business days to calendar days for comparison to Ontario dates.
2. IR: Initial Review, SR: Supplementary Review
3. CCE is shown as a light-colored bar at the end of CIA application as this is optional.
4. Timelines for Mid-Sized generation connections in Ontario are not well defined for the DCA and CCA processes and are said to be negotiable. It is expected that these timelines will at least match the duration shown for small connections.

FERC rules in the USA allow a ‘Fast Track’ process in certain cases with potentially shorter processing times. In California, Rule 21 applies which recognizes Non-Export facilities separately to which ‘Fast Track’ process is applicable. However, for the non- ‘Fast Track’ process, the application time duration for these facilities appears to be the aligned with those in Ontario.

Based on the Hatch analysis, the summary of the findings and recommendations is as follows:

1. Non-exporting BTM energy storage can be considered a subclass of load displacement generators. However, the OEB does not explicitly outline load displacement application processing requirements in the DSC. Consequently, the LDCs apply a general application process to these connections. It is recommended that a load displacement timeline or process flow be developed or stated more explicitly in OEB DSC with

consideration given to specific characteristics of the BTM inverter-based non-export systems.

2. Within the ‘Fast Track’ application process under California’s Rule 21, by passing the initial review stage successfully, the time taken for the application process is greatly reduced as compared to the timelines seen for much of Ontario. It is recommended that the OEB and Ontario LDCs consider the ‘Fast Track’ application process under California’s Rule 21 to reduce the applications processing times for non-export inverter-based systems while ensuring that technical requirements for these systems can be met with their own specific framework. The California ‘Fast Track’ process is outlined in Figure 3-7, which expedites the supplemental review including various penetration and power quality tests for non-exporting systems.

3. If the ‘Fast Track’ application fails the initial review stage, there is still a possibility that only minor modifications need to be made or a supplemental review will be sufficient. It should be noted however, if after the supplemental review has taken place and it is deemed that a full study is required, this can result in a timeline that surpasses the timeline seen in Ontario.

4. Hydro One, requires connection impact assessments to be completed for connections done in LDCs connected to it’s system. It is not immediately clear the processes that Hydro One takes during the “Engineering, Procurement and Construction” Phase of their process outside of the possible 45 days to assign a project manager and have a kick-off meeting. OEB’s DSC specifies the need for technical review of applicants/generator’s engineering drawings. OEB specifies connection times after the completion of all approvals, notwithstanding issues in commissioning and testing which are out of the distributor’s control. In Hatch’s experience interconnection projects have similar approval, engineering, commissioning, and construction milestones. Hatch recommends that the processes after the completion of the CCA, and the associated milestones be added to the connection process to allow distributors to properly plan and organize connections after the CCA stage.

5. Based on the Enel X case experience, Hydro One’s review process of the detailed engineering deliverable is done in tandem with several different teams. Each team was found to provide review at different times. Hatch believes that receiving critical comments as soon as possible would be most beneficial for the progress of the connection. Hatch believes comments provided that are not critical, in that they do not require a pause of review until corrected, can be provided as soon as available by each team separately.

6. For many cases, depending on feeder configuration, and where the BTM energy storage source is less than 33% of the feeder minimum load, the anti-islanding features of certified inverters together with certified minimum import power relays can be a viable form of anti-islanding protection as an alternative to direct transfer trip. The combination of the feeder loading and configuration are more relevant to determining the need for a transfer trip than simply the size of the energy storage facility.

7. In cases where transfer trip is required, transfer trip implementation costs vary in a wide range and are mainly affected by the number of existing transfer trip and the complexity of the control scheme. With the current Ontario process, the capital costs of interconnection requirements such as the Direct Transfer Trip may only have finalized in later stages of the project cycle. The unknown final cost of the transfer trip has a significant negative effect on the project cost estimation and planning. The potential range of these costs can suddenly cause a project to become an unfeasible investment. Providing a narrower estimate of these costs at earlier phases would help reduce this risk and encourage more investment in BTM ESS systems for load displacement.

8. Recent studies in Canada have tested alternates to direct transfer trip and have shown cases where they can be implemented successfully even with synchronous generators with a large relative size compared to the feeder load.

9. Currently, monitoring systems are required by most LDCs for BTM energy storage, although these requirements are not mentioned explicitly in IEEE standards. However, it is understandable that monitoring is useful to LDCs in order to know the feeder demand in real time for LDC operation and reenergization processes. It is recommended that more studies be done to evaluate the monitoring need with regards to the ratio between DG facility and minimum feeder loading.

# 3. Application Process Comparison

This Section compares, at a high level, the various processes found in Ontario and other jurisdictions with regards to the application times and steps. Although FIT processes are no longer contracted by IESO in Ontario, Ontario LDCs and utilities often use the previously established processes and technical requirements under FIT as a basis for all new renewable or energy storage connections. This Section focuses primarily on the connection application process before its approval, as the time it takes after the connection is approved can vary greatly on construction, permitting, and other project-specific factors. Unless otherwise specified, all dates and durations are in calendar days.

## 3.1 Regulatory - Ontario Energy Board (OEB)

The Ontario Energy Board (OEB) is the independent regulating authority for the electricity and natural gas sectors in the province of Ontario. The OEB defines the rules and regulations which define the safe operation and control of the provincial electric grid. The OEB's Distribution System Code (DSC) (last revised on March 15, 2018) stipulates the minimum requirements a distributor must adhere to in complying to it's licence and the Energy Competition Act 1998 obligations. This sub-section specifically considers the application process that OEB has defined in Appendix F of the DSC.

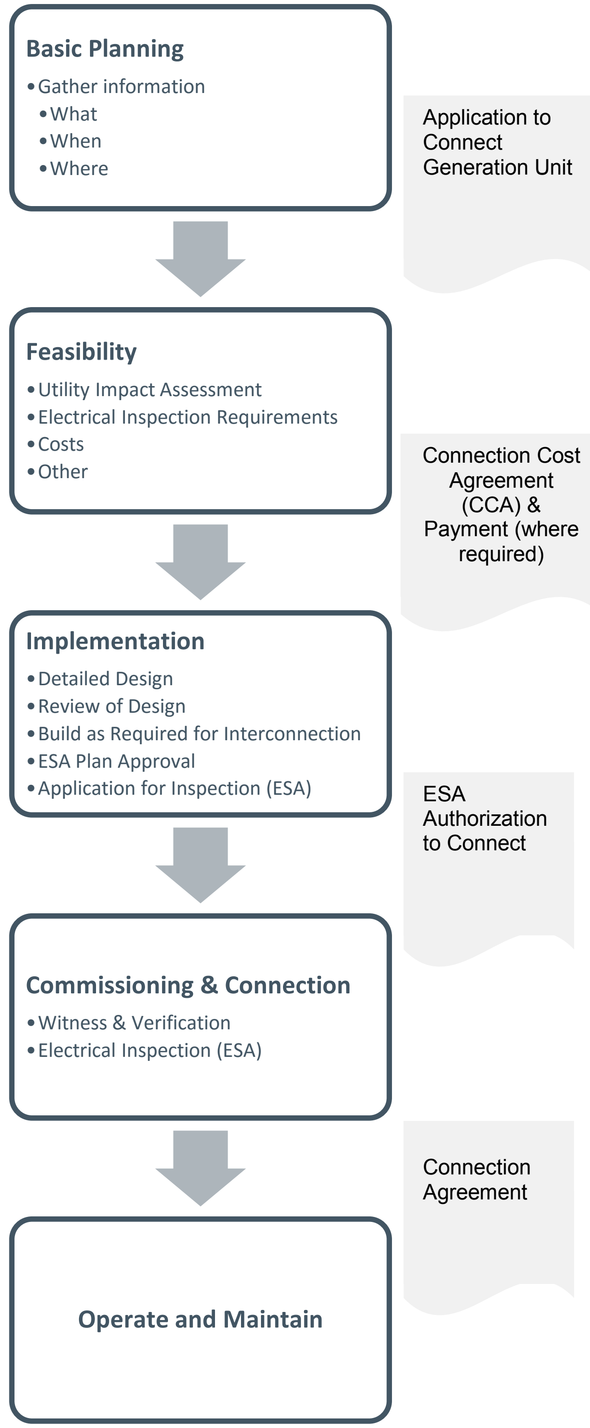


**Figure 4-1: OEB Generation Connection Process Summary**

The flowchart in Figure 4-1 is adapted from Appendix F of the DSC and indicates the general flow of the connection process. OEB DSC Section 6.2 provides the connection process for embedded distributed generation facilities. The individual processes are further broken down depending on the size of the generator. The LDCs studied in Ontario follow the definition of the generation sizes and stipulate different requirements depending on application's connection size as shown in Table 3-1.

**Table 3-1: OEB DSC Generator Classification (as per Appendix F of DSC)**

| Generator Classification | Rating |
|---|---|
| Micro | < 10 kW |
| Small | ≤ 500 kW connected on distribution system voltage <15 kV<br>≤1 MW connected on distribution system voltage ≥ 15 kV |
| Mid-Sized | ≤10 MW but > 500 kW connected on distribution system voltage < 15 kV<br>>1 MW but ≤10 MW connected on distribution system ≥ 15 kV |
| Large | > 10 MW |

In Table 3-2, the OEB guidelines for connection assessment timelines are summarized. A detailed breakdown can be found in the OEB's DSC Appendix F for the various connection types. Further details for the processing times can be found in OEB's DSC Section 6.2.3 – 6.2.25a.

Another important consideration is the connection process involved with load displacement type systems. OEB's definition of "load displacement" applies when embedded generation is used entirely for the "customer's own consumption". The connection process for load displacement generators seems to be unclearly defined in OEB's DSC 6.2.1 and OEB's DSC Appendix F.

OEB's DSC 6.2.1, implies that behind the meter storage which can be argued as a load displacement system should not be required to follow the processes of 6.2 of the DSC. Whereas DSC Appendix F suggests that load displacement is included as part of the process. As implied by the third step in many of the outlines in DSC Appendix F "Step 3", a generator is meant to develop the facility's purpose, in which load displacement is an option, prior to beginning this process.

The apparent contradiction of Section 6.2 and Appendix F of the DSC was followed up by Hatch with OEB. OEB provided a response which stated the following:

> *"[W]here there is a discrepancy between the DSC and Appendix F.1, the DSC governs. Generally, where section 6.2 does not apply as per section 6.2.1, a distributor is expected to use their own connection policies as set out in their Conditions of Service"*

Therefore, OEB allows Ontario LDCs to the authority to create connection policies that fill in this procedural gap. Consequently, Ontario LDC's have shown to follow the standard procedure for processing times regardless of load displacement.

**Table 3-2: OEB DSC Connection Application Process Duration Summary (Calendar Days)**

| Duration Summary | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | Initial Consultation[4] | Connection Impact Assessment[5] | Offer to Connect and (Optional) Initial Cost Estimate[2, 3] | Connection Cost Agreement[7] | Connection Agreement (and Review) | Total Duration[1] |
| Micro | Existing Customer w/o site visit | | | 15 days | 45 days | 45 days | 105 days |
| | Existing Customer w/ site visit | | | 30 days | 45 days | 45 days | 120 days |
| | New Connection w/ site visit | | | 60 days | 45 days | 45 days | 150 days |
| Small | No Grid Reinforcement | 15 days | 60 days | | 45 days | 60 days[6] | 180 days |
| | Grid Reinforcement | 15 days | 90 days | | 45 days | 180 days[6] | 330 days |
| Mid-Sized | | 15 days | 60 days | 90 days | Negotiated[8] | | 165+ days |
| Large | | 15 days | 90 days | 90 days | | | 195+ days |

1. This duration does not include optional tasks such as the Connection Cost Estimate or the time it takes during commissioning and testing to establish any permitting and connection agreements based on design and construction.
2. Micro-Generation may take an additional 5 days to connection once all ESA approvals are complete (see DSC 6.2.7). DSC does not make an apparent reference to cost estimate for micro facilities.
3. If comments are required for transmitter or another distributer whose system may also be impacted, the connection cost estimate may take longer than 90 days to allow connecting distributor to incorporate the comments. (see DSC 6.2.16 and 6.2.17)
4. Information provided for the initial review must be correct and full, before the 15-day timeline can be agreed to. The date begins from the date of request for information/meeting (see DSC 6.2.9.2)
5. Distributor has 10 days to advise another distributor or transmitter of the proposed connection. Transmitter or other distributor may need to do a transmission or additional distribution impact assessment (see DSC 6.2.14A). This process may greatly increase the project assessment timeline.
6. Once the connection agreement is signed and all approvals are complete it is expected to take (assuming no commissioning or testing delays) 60 days or 180 days to connect the facility depending if it requires distribution system reinforcement or not (respectively), see DSC 6.2.21
7. OEB's DSC does not make a clear indication to the timeframe for the Connection Cost Agreement (DSC 6.2.18). HONI indicates the CCA must be provided 45 days in advance of 6-month deadline. So, it is assumed CCA can take up to 45 days to turn around.
8. Large and Mid sized installations do not have a specific timeline for the Connection Agreement. The timelines are specified as being negotiated during Plan Commitment (See DSC Appendix F.1.3 and F.1.4). It is expected that these timelines will at least match the duration shown for small connections.

OEB also specifies some time durations for correspondence and processing that are associated with the deliverables above. Some additional time may be required for/ in case of the following:

1. OEB specifies that a distributor may need to withhold information about a feeder if a load characteristic can be determined about a specific entity on that feeder from the information (see DSC 6.2.9.4). If information is critical, getting consent for the release of the information may delay the process.

2. OEB does not specify the extent of delay due to rework. According to the Appendix F of the DSC (see process flow diagrams) if rework is required, a process step may be reset. As an example, consider; if the Connection Impact Assessment requires rework on the Connection Application, the timeline may be reset to require another 60 days from the resubmittal of the corrected or changed application.

OEB's DSC further specifies the need for technical review of applicants/generator's engineering drawings. The timeline for this review stage is not explicitly stated. OEB specifies the consequent timeline after the completion of all these approvals and review, notwithstanding issues in commissioning and testing which are out of distributor control.

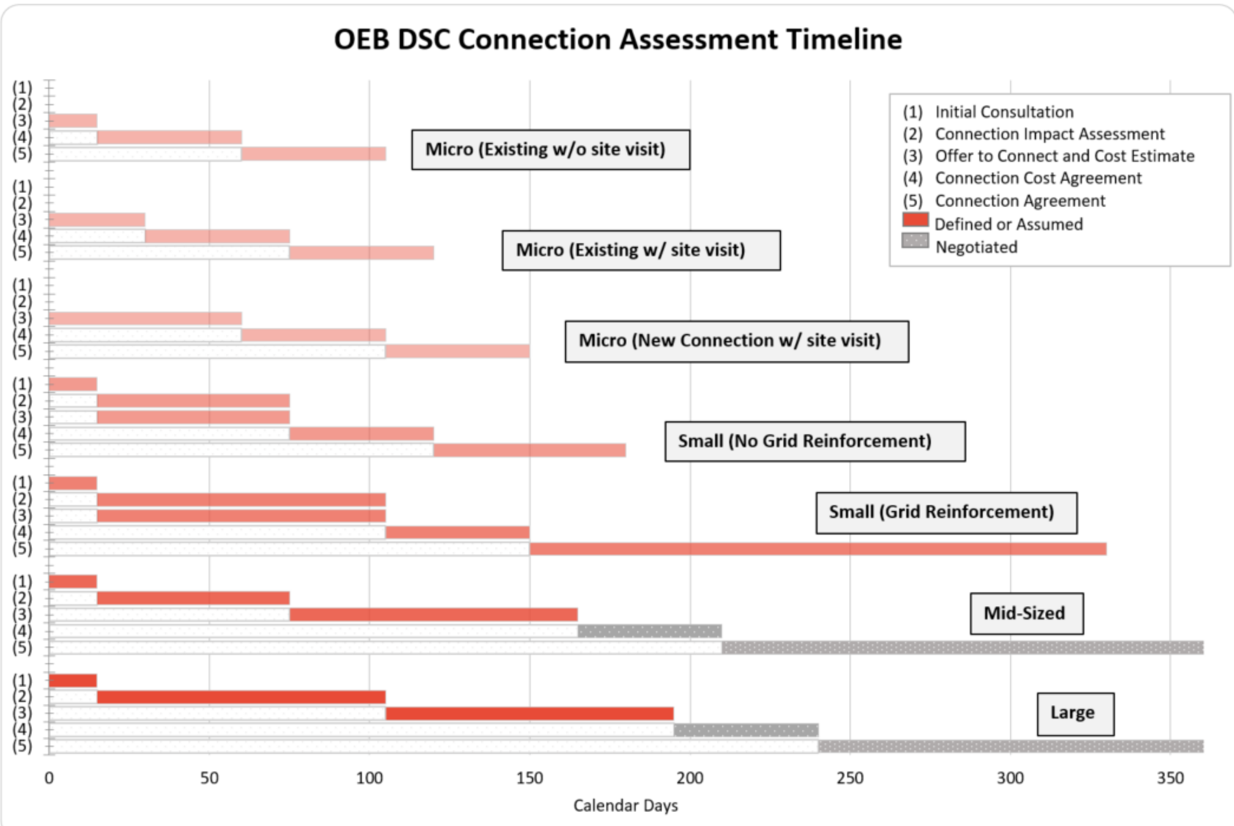


**Figure 3-2: OEB DSC Connection Application Process Timeline**[2]

1. The timeline above does not take into consideration the time that may be needed if rework is necessary in any stage of the process. The effect of rework on time line is also unclear. This of course is dependant on the extent of the rework required, and according to OEB's Appendix F process flow diagrams, may restart a stage of the process.
2. OEB's DSC does not make a clear indication to the timeframe for the Connection Cost Agreement (DSC 6.2.18). HONI indicates the CCA must be provided 45 days in advance of 6-month deadline. So, it is assumed CCA can take up to 45 days to turn around.

[2] OEB uses calendar days (unless otherwise specified – see DSC definition of "day") in the above timelines

3. Large and Mid sized installations do not have a specific timeline for the Connection Agreement. The timelines are specified as being negotiated during Plan Commitment (See DSC Appendix F.1.3 and F.1.4). It is expected that these timelines will at least match the duration shown for small connections.

Per OEB DSC, the time that an LDC is allowed to do the tasks required by them in the above for a small generator without grid reinforcement can up to 25 weeks (180 days). OEB specifies that a preliminary cost estimate would be provided after initial consultation which may help with budgetary approvals. If a full estimate is required, the Connection Cost Estimate can take several months from application. Further, if correspondence times are allowed between reviews and other matters, this time duration may increase. These time durations are compared later in this report with those allowed in other jurisdictions.

## 3.2 Analysis of Ontario LDCs

### *3.2.1 Hydro One Networks Incorporated (HONI)*

Hydro One is the largest electric transmission and distribution service provider in Canada, servicing 38% of Canada's population. Hydro One services and operates thousands of kilometers of transmission and distribution lines in the province of Ontario. Its large footprint also makes it the primary transmission service provider for Ontario LDCs such as Toronto Hydro, and Alectra. However, Hydro One also operates distribution (44 kV and below) networks around Ontario.

Hydro One is required to follow the OEB's Distribution System Code as well as regulations from the Independent Electricity System Operator (IESO). Since there is no specific stream for BTM energy storage interconnection or more generally load displacement, the process for the closest stream called the Feed-in-Tariff (FIT) is presented.

The following process is measured in calendar days and does not consider the time that it may take to have correspondence between parties whether this correspondence is defined in the application process or not.

HONI may restart an application process step if rework is required, which can increase the timeline required for approval of connection. Hydro One's connection process is defined as follows:

1. **(Optional) Pre-consultation - Form A**

   Assist proponent in gathering information necessary to apply for a "FIT", such as point of connection as well as transmission and distribution capacity.

   This step can take 15 days upon receipt of completed Pre-FIT Consultation.

2. **FIT Contract Application**

   Handled by the IESO and is expected to take 60 days upon IESO FIT application.

3. **Connection Impact Assessment (CIA) Form – Form B**

   After (FIT) contract has been awarded, applicant files Connection Impact Assessment (CIA) for formal assessment of impact of connecting generator to the system. System

Impact Assessment (SIA) is done for >10MW. High-level connect cost assessment will be provided as part of CIA package.

60 days upon receipt of completed CIA application Form B (longer than 60 days if project involves other LDCs)

4. **(Optional) Connect Cost Estimate (CCE)**

   Detailed estimate of the project costs incurred to HONI.

   This step can take 90 days upon the receipt of completed CCE study agreement

5. **Connection Cost Agreement (CCA)**

   The CCA is an agreement which will require the generator to cover the cost incurred by HONI for the connection. OEB's DSC section 6.2.18 requires such an agreement but does not specify a clear timeframe. The CCA must be provided 45 days in advance of 6-month deadline. So, it is assumed CCA can take up to 45 days to turn around.

6. **Engineering Procurement and Construction**

   After CCA is submitted and payment is given, detailed design and construction may begin. A kick-off meeting is scheduled with an assigned HONI project manager within 45 days after the CCA is signed as per HONI guidelines. Once designs and approvals are done, then the Distribution Connection Agreement (DCA) is signed and the in-service date is determined. The DCA must be provided 60 days in advance of the proposed in-service date as per HONI recommendation[3]. So, it is assumed DCA process can take up to 60 days to turn around. Timelines for this stage of the project are only provided after the CCA has been completed and can be specific to each project. A review of detailed engineering and connection may be required based on anecdotal experience.

These time frames were specified by Hydro One and thus may only apply to Hydro One specific work. Additional time may be allocated for correspondence and error correction in application process.

As specified in the OEB DSC application process, there are often several days (sometimes up to 15 days) allocated for correspondence or to address problems that may arise in the process. The timelines below therefore show the specific key application milestones but does not consider the times spent for correspondence or addressing problems. Another source of additional delay can come due to errors or changes in the application.

The summary of these items is listed in Table 3-3.

[3] See HONI "Distribution Connection Agreement" webpage: https://www.hydroone.com/businessservices_/generators_/Pages/distributionconnectionassessment.aspx

**Table 3-3: Hydro One Connection Application Process Duration Summary (Calendar Days)**

<table>
<tr><th colspan="9">Duration Summary</th></tr>
<tr><th></th><th>Pre-consultation</th><th>Connection Impact Assessment Form – Form B [2]</th><th>Connection Cost Estimate (Optional)</th><th>Connection Cost Agreement[3]</th><th>Kick-off and PM assignment[3]</th><th>Distribution Connection Agreement[4]</th><th>Total Duration[1]</th></tr>
<tr><td>Micro</td><td></td><td>15 days +<br>5 days Modification</td><td>90 days</td><td rowspan="2">45 days</td><td rowspan="2">45 days</td><td>45 days</td><td>155 days</td></tr>
<tr><td>Small Mid-size and Large</td><td>15 days</td><td>60 days</td><td>90 days</td><td>60 days</td><td>225 days</td></tr>
</table>

1. This does not include correspondence, optional steps or rework.
2. This does not include rework that may be required. Thus, it can be expected that changes that are critical to connection design may pause the review process until corrected. This can increase the time required for approval of CIA application.
3. It is not apparent if HONI's process for the CCA and kick-off meeting require the same durations for micro and non-micro generation. For comparison a conservative approach of assuming these durations are consistent is indicated.
4. The DCA must be provided 60 days in advance of proposed in-service date. So, it is assumed DCA process can take up to 60 days to turn around. There is no distinction between size of generators for this requirement, so it is assumed to be consistent of Small, Mid, and Large sizes.

The exact processes outlined in OEB's DSC were not found to explicitly match Hydro One's FIT connection process. This does not suggest that Hydro One's process deviates from the OEB's requirements, as Hydro One seems to conform with the general 15-day and 60-day time frames.

### 3.2.2 *Toronto Hydro*

Toronto Hydro Corporation (Toronto Hydro) owns and operates the electric distribution system for the City of Toronto. Toronto Hydro notes the various process milestones and times in its Distributed Generation Requirements. In this regard the general process for connections is defined below. Toronto Hydro stipulates response requirements which generally align to 5 – 10 days for correspondence in major milestones (CIA completion, cost estimate, etc.)

In particular to projects Toronto Hydro deems as part of FIT, Capacity Allocation projects for small, mid-sized, and large facilities must wait for CIA, Distribution Availability Test (DAT), and Transmission Availability Test (TAT) before being given a Connection Agreement. Toronto Hydro also specifies once the Connection Agreement has been signed, the customer must complete detailed design and engineering within 6 months prior to the connection of the site (connection date specified in Connection Agreement).

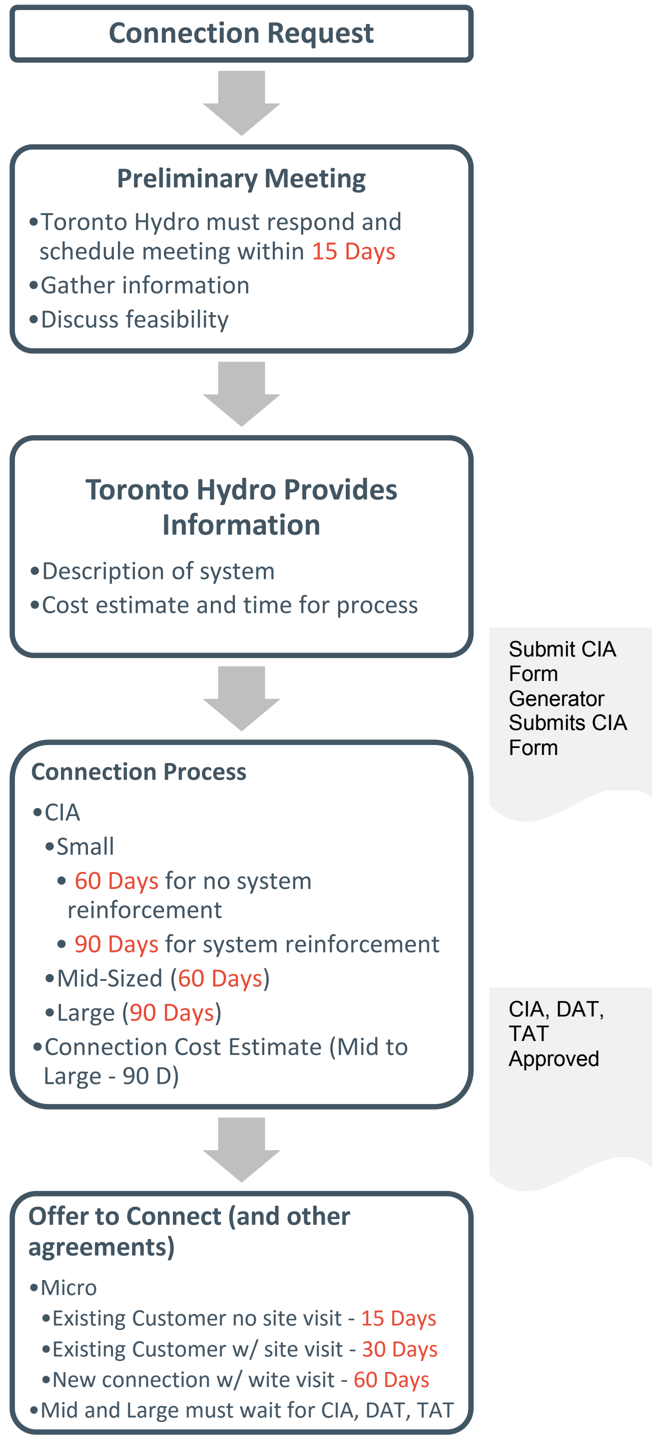


**Figure 4-3: Toronto Hydro Distributed Generation Connection Process Summary**

Toronto Hydro's processing time aligns with OEB's defined application connection processing time.

### *3.2.3 Alectra Utilities*

Alectra operates and maintains electric grid in the Greater Golden Horseshoe area in southern Ontario, operating under OEB's jurisdiction. Alectra and its connection process are stipulated in Alectra's Conditions of Service. Alectra plays a major service role in North Western Greater Toronto Area cities such as Mississauga, Vaughn and Markham.

Process:

1. Initial contact and Alectra to provide information for connection
2. Initial consultation: (Form A – Pre-FIT Consultation),
3. Connection Impact Assessment (Form B)
4. Connection Cost Estimate (by Alectra)
5. Design and build – Connection Cost Recovery Agreement
6. Connect, Operate, Maintain – Connection Agreement outlines the connection and roles and responsibilities of the parties
7. May need additional approvals from IESO (SIA), OEB, Electrical Safety Authority (ESA)

Alectra does not explicitly list their internal processing times, however it is expected they follow OEB processing times.

## 3.3 Analysis of Other Jurisdictions

In this Sections, DR application processes in a number of several regulatory bodies and LDCs in other jurisdictions presented.

### *3.3.1 Regulatory – North American Electric Reliability Corporation (NERC)*

The North American Electric Reliability Corporation (NERC) is an international regulatory body which aims to mitigate reliability and security risks in the North American electric grid. NERC develops standards, conducts assessments; and provides education, training, and certification to owners, users, and operators of the bulk North American power system or Bulk Power System (BPS). NERC's jurisdiction includes continental United States, Canada and northern Baja California, Mexico.

NERC establishes bulk power system requirements while allowing specific regulations such as FERC and OEB to control regional areas. NERC has invested efforts into technical considerations for inverter-based systems and has working groups that conduct research that may be used as input for the maintenance of standards such as IEEE 1547. However, NERC has not issued any specific recommendations for connection processes at a tri-national level.

### *3.3.2 Regulatory – Federal Energy Regulatory Commission (FERC)*

The Federal Energy Regulatory Commission (FERC) is an independent entity that regulates the interstate transmission of natural gas, oil and electricity[4]. FERC's jurisdiction contains California (CAISO), Texas (ERCOT), and other United States electricity markets. FERC has defined a process by which its jurisdiction follows to ensure consistent procedures. FERC has defined the small generator (< 20MW) connection procedures in their Small Generator Interconnection Procedures (SGIP) report.

The procedures and timelines described in this Section are assumed to be business days. This is assumed on the basis that CAISO specified equivalent time lines and explicitly stated them as business days.

FERC offers the ability to initiate a Fast Track process to expedite the installation of generation that fits certain considerations. Generators must be eligible to enter the process and then are passed through initial review which involves a set of requirements or "Screens" that offer a way to test the validity of the connections to the Fast Track connections. Eligibility for the inverter-based Fast Track process must first be checked. The following requirements allow eligibility for an inverter generator to be considered for fast tracking:

- Connection to lines below 69 kV
- Code, standard, and certifications (specified in Attachment 3 and 4 of SGIP)
- Certified Inverter-Based systems can be eligible for Fast-Track option as shown in Table 3-4.

**Table 3-4: Fast Track Eligibility for Inverter Based Systems (SGIP)**

| Line Voltage | Fast Track Eligibility Regardless of Location | Fast Track Eligibility on a Mainline[5] and ≤ 2.5 Electrical Circuit Miles from Substation[6] |
|---|---|---|
| < 5 kV | ≤ 500 kW | ≤ 500 kW |
| ≥ 5 kV and < 15 kV | ≤ 2 MW | ≤ 3 MW |
| ≥ 15 kV and < 30 kV | ≤ 3 MW | ≤ 4 MW |
| ≥ 30 kV and ≤ 69 kV | ≤ 4 MW | ≤ 5 MW |

[4] www.ferc.gov
[5] For purposes of this table, a mainline is the three-phase backbone of a circuit. It will typically constitute lines with wire sizes of 4/0 American wire gauge, 336.4 kcmil, 397.5 kcmil, 477 kcmil and 795 kcmil.
[6] An Interconnection Customer can determine this information about its proposed interconnection location in advance by requesting a pre-application report pursuant to section 1.2.

A connection being eligible may not guarantee that it passes the initial review (hence may have to go to further study). A complete pass of the Fast Track screens offers a direct route to a connection agreement which allows a quicker turnaround for certain generators as compared to standard processes. The assessment by the transmission provider must be completed and results presented in 15 business days from the accepted interconnection request.

If the connection request does not pass the initial review it may still be allowed to pass with small modifications or a supplementary review as discussed in the Customer Option Meeting. The total delay from the review and the set up of the meeting expected to be at most 15 business days. If a supplementary review is required, it takes at most 30 business days from the receipt of payment. This Fast Track process and a supplementary review allows multiple opportunities to bypass a full System or Connection Impact Assessment (study). If an agreed connection cannot be established, a detailed study is done. The general process is shown in Figure 4-4.

### *3.3.3 Alberta*

#### *3.3.3.1 EPCOR*

Alberta is the fourth most populous province in Canada with Edmonton as it's capital city and is the primary supply and service hub for Canada's northern resource and petroleum industries. Thus, Alberta is a good example to study and compare with Ontario for both their differences and similarities. EPCOR is one of the largest utilities in Alberta as they supply Edmonton and several other cities throughout Alberta.

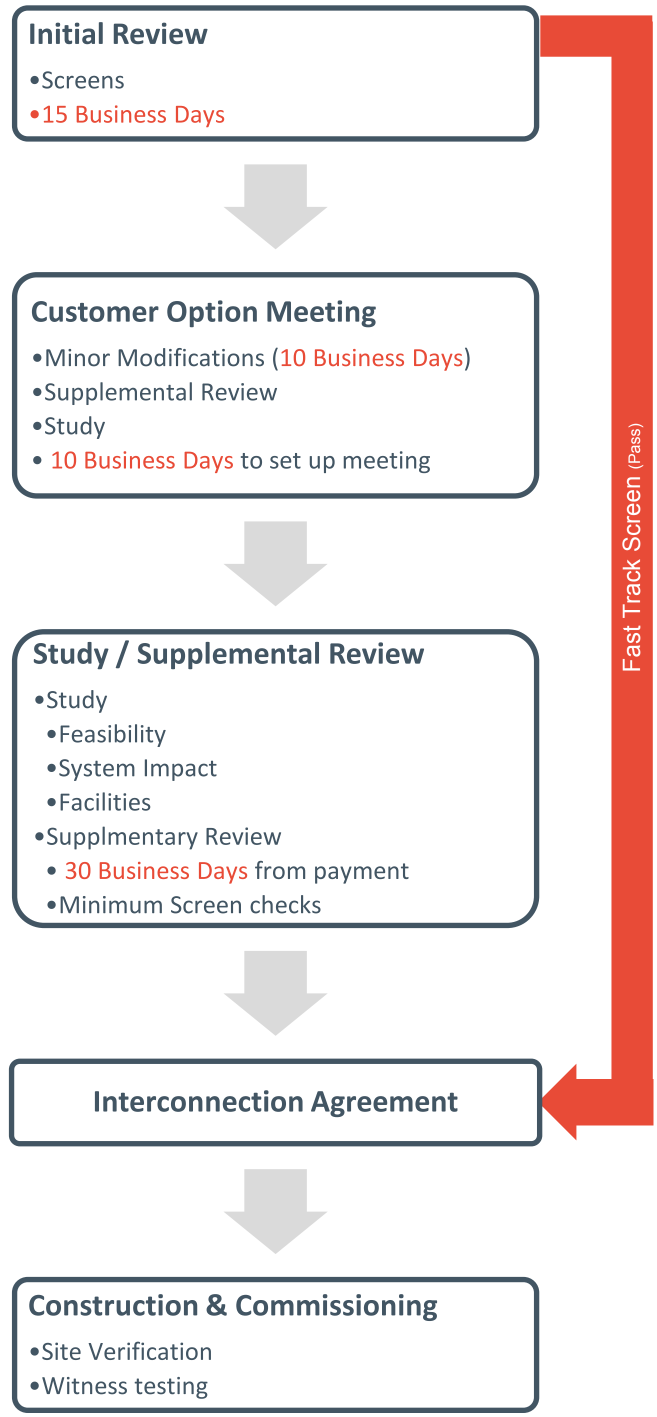


**Figure 4-4: FERC Connection Process Summary**

AUC (Alberta Utilities Commission) defines Micro-generation as being less than 5MW renewable energy installations across Alberta, including fuel cells. In this report it is assumed that this will also include the BTM energy storage installations.

The EPCOR Application Process for Micro-Generation is described below.


1. Planning
   a. If the micro-generation project will be 20 kW or larger, contact EPCOR's customer engineering team before starting the design. There may be special requirements for these larger micro-generation systems that EPCOR can help identify early on.
   b. If the system is 150 kW or larger, or on the network, it is necessary to contact EPCOR to request an Interconnection Study before applying to the City of Edmonton for a permit.
      i. According to the call with EPCOR, the interconnection study may take 2 days to 2 weeks.
      ii. Design Drawings; Single Line Diagram, Site Plan/Real Property Report, etc., stamped by the manufacturer's engineer or showing CSA approval.
2. Permitting
   a. All applicable permits (electrical, building etc.)
   b. According to the call with City of Edmonton, the permitting process takes at least 1 week, normally takes more than two weeks.
3. Complete EPCOR's Application Form & include all necessary documents
   a. A copy of the City of Edmonton electrical permit issued and may include a copy of the building permit issued for site construction.
   b. Design Drawings
   c. Third Party Consent Form (if a contractor/consultant is acting on behalf of the customer).
4. Wait for application review – within 14 days[7]
5. Receive interconnection agreement

[5] See "Our Commitment to You" at: www.austinenergy.com/ae/about
[7] See "Becoming A Micro-Generator" at www.epcor.com

The overall processing time is not defined beyond what is described above and it is dependent on the size of the facility and the results of system studies.

### *3.3.4 Texas*

Texas is the second largest state in the U.S. and has a power grid which is largely isolated from the rest of the country. The Electric Reliability Council of Texas (ERCOT) operates the majority of the Texas grid. Two major electric utilities in Texas have been selected for analysis based on the quality of information available and the unique aspects of their processes.

#### *3.3.4.1 Austin Energy – Technical Requirements*

Austin Energy serves the city of Austin, Texas. It is one of the largest cities in the state, with approximately 1 million residents. The utility has been recognized nationally for its reliability[5] and has embraced the use of green energy and continues to plan for the expansion of renewable technologies. The technical standards available for distributed generation are well documented and gives a clear insight into the operation of the city of Austin's distribution system. More specifically, the distribution interconnection guide provides the customer with an adequate understanding of what is necessary from both a protection and monitoring standpoint and ensure reliable operation of the grid. In this report, these technical standards will be discussed and compared with various jurisdictions across Canada and the U.S.

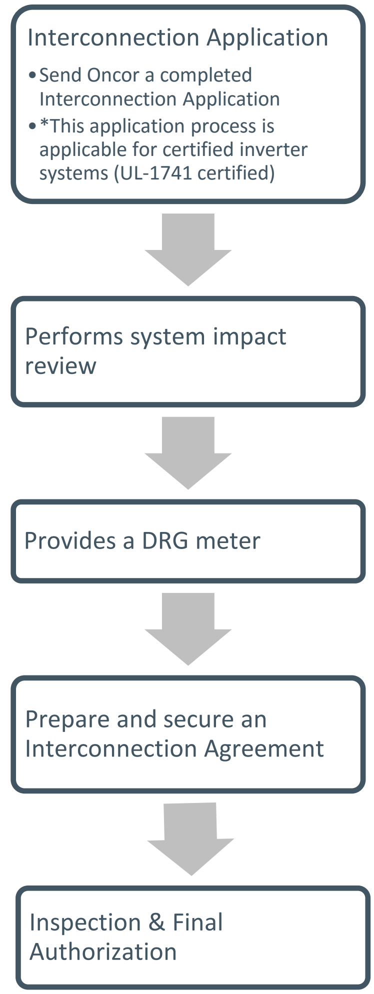


**Figure 4-5. Texas (Austin Energy) Connection Process Summary**

#### *3.3.4.2 Oncor – Application Process*

Oncor is Texas's largest transmission and distribution electric utility and serves approximately 10 million residents in Texas. Oncor provides the customer with various options for Distributed Renewable Generation (DRG) connections. When applying for DRG connection, UL-1741 certified inverter-based systems are distinguished and have their own application for a specific application form. Enel X's UL-1741 certified battery pack systems are eligible for this type of application. Allowing a separate inverter application process helps to streamline the process. The basic steps for interconnection are outlined below:

**Process (Certified Inverter Systems):**

1. Interconnection Application
2. System impact study and review of application

3. Prepare and secure the Interconnection Agreement
4. Receive DRG Meter
5. Final authorization and operation

**Table 3-5: Texas (ONCOR) Application Processing Time Duration Summary**

| | Duration of Interconnection Application & System Impact Study | Duration to Receive DRG Meter from Oncor | Total Duration |
|---|---|---|---|
| Pre-certified | Up to 30 days [5] | Up to 30 days [6] | Up to 60 Days[1] |
| Non-certified | Will vary depending on particular aspects of the application. | | |

1. Processing time has been estimated by addition of time required for interconnection steps and information available. Actual timeline will include time for correspondence and final authorization in Step 5.

The process outlined above are for certified distributed renewable energy systems. A certified DRG system, according to Oncor, is an inverter-based system which has been tested and certified to meet the standards specified in UL-1741 Utility Interactive (Underwriters Laboratory). In this case, Enel X battery pack systems have been found to be UL-1741 certified which would result in a well-defined and shorter application process.

### *3.3.5 California*

California was selected for this study since it is one of the pioneers in energy storage interconnection in North America. California Electric Rule 21 is a tariff that describes the interconnection, operation, and metering requirements for interconnection of generation facilities to a utility's distribution system. The tariff provides customers that would like to install generation or storage facilities on their premises with access to electric grid while maintaining the grid safety and the reliability of the transmission and distribution systems.

The Rule 21 Interconnection requirements applies to the California utilities including PG&E, SCE, and SDG&E. In this report "Rule 21" is referenced from PG&E's document and will be referred simply as the Rule or Rule 21. This Rule describes the Interconnection, operating and Metering requirements for those Generating Facilities to be connected to Provider's Distribution and Transmission System over which the California Public Utilities Commission has jurisdiction. Despite the type of generation facility, all Generating Facilities seeking Interconnection with Distribution Provider's and Transmission System shall apply to the California Independent System Operator (CAISO) for Interconnection.

This Rule has been harmonized with the requirements of American National Standards Institute/Institute of Electrical and Electronic Engineers (ANSI/IEEE) 1547-2003 Standards for Interconnecting Distributed Resources with Electric Power Systems.

Figure 4-6 illustrates the Rule 21 interconnection Technical Framework Overview. As stated in Rule 21, applicants can apply for a Fast Track process which can reduce the application processing time since It bypasses the detailed

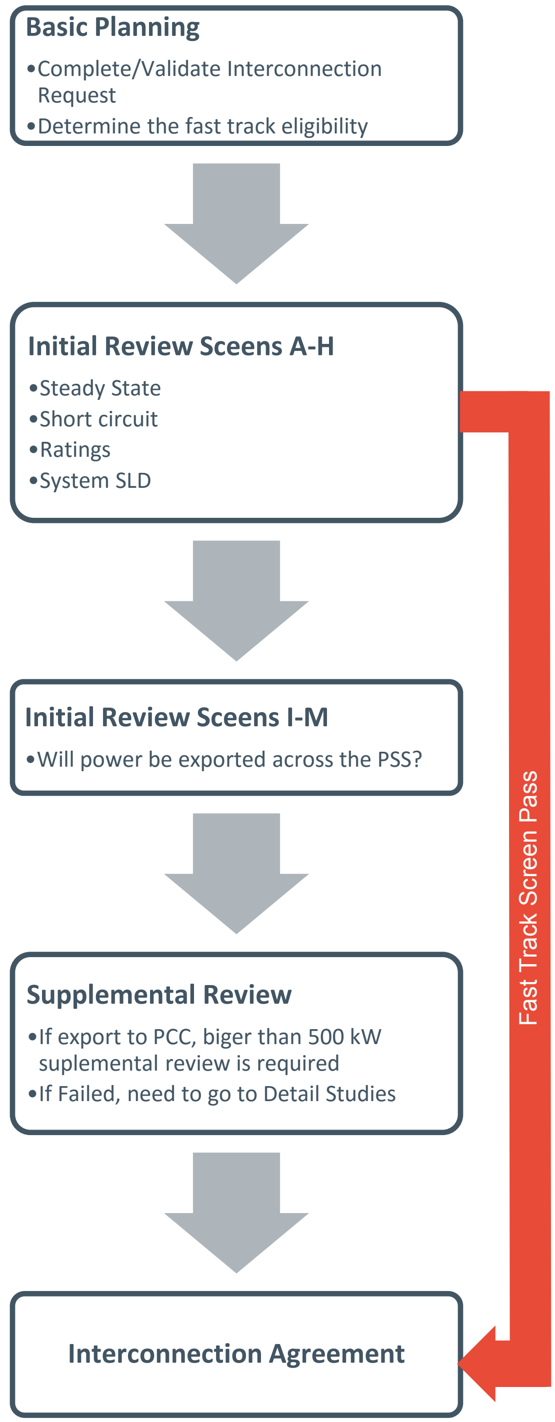


**Figure 4-6: Rule 21 Interconnection Connection Process Summary**

study. A decision is made based on different variables including but not limited to the facility size, feeder min/max loading, short circuit level, etc. Fast Track applications could be applicable to Enel X BTM deployments as they may meet the non-export criteria.

The summary of the Fast Track application for a facility considered as Non-Export/NEM-1 is presented below:

1. Initial review (Network Secondary, Clarified Equipment, Voltage Drop, Transformer Rating, Single Phase Generator, Short Circuit Current Contribution, Short Circuit Interrupting Capability, Line Configuration)
2. Power should not be exported across the PCC
3. Proceed with interconnection

Table 3-6 provides the summary of the application processing times based on the application type. The complete application process is presented in Figure 3-7 and can be accessed in Rule 21 G. Engineering Review Details.

**Table 3-6: California Application Processing Time Duration Summary (Business Days)**

<table>
<tr><th colspan="9">Duration Summary</th></tr>
<tr><th colspan="2"></th><th>Initial Review</th><th>Supplementary Review</th><th>Scope Meeting / Detailed Study Agreement</th><th>Distribution Impact Study[6]</th><th>Facilities Study[5]</th><th>Interconnection Agreement</th><th>Total Duration[1]</th></tr>
<tr><td colspan="2">Not Fast Track</td><td>20 days[4]</td><td></td><td>5 days (Meeting) + 15 days (Agreement)</td><td>30 days</td><td>45-60 days[5]</td><td>30 days</td><td>145-160 days</td></tr>
<tr><td rowspan="2">Fast Track[2]</td><td>Pass</td><td rowspan="2">15 Days</td><td></td><td></td><td></td><td></td><td>15 days</td><td>30 days</td></tr>
<tr><td>Fail</td><td>20 days + 10 days for Options Meeting</td><td></td><td></td><td></td><td>15 days</td><td>45 days</td></tr>
</table>

1. Any request from Distribution provider should be responded in 3 business days. Actual time will differ when considering correspondence allowances.
2. Pass is the shortest time with Fail requiring supplemental review and no study
3. The SGIP does not specify a limit to the interconnection timeline and only proposes reasonable effort to stay in timeline, and that a timeline can be defined by the customer and transmission entity during the Scoping meeting. An estimate of 45 days is the aggregated correspondence times excluding the actual study work.
4. Rule 21 F.3.a states that any path that results in the requirement of a Detailed study must first pass "Screens Q and R" as applicable.
5. For connections requiring grid modifications the Interconnection Facilities Study may take 60 days (Rule 21. F.3.b.viii) but may be waived by Distributor.
6. The impact study review must pass screen Q to be allowed to go to the Distribution Group Study process in which the Impact Study is referred to as the DGS Phase I/II Interconnection Study. If consensus is not found it will move to Phase II Interconnection Study which is allowed an additional 60 business days to complete

The Fast Track option can reduce processing times by over 3 months as the Impact and Facilities studies can take several weeks to complete (120 business days in total, or 168 calendar days). It should also be noted that if there is no feasible agreement reached between the utility and the generator at the end of the Fast Track evaluation, the process may proceed to a full study. As compared to starting as a non-Fast Track connection directly, this initial and supplementary review could create delays of over 30 days.

Although meeting a Non-Export criterion can increase the chance of Fast Track eligibility, the processing time will not change for these applications and the same 15 days for the initial review is required.

A Non-Export AC/DC converter can guarantee the Fast Track eligibility if the NRTL-certified equipment is used. However, this condition may not be directly applicable to Enel X inverters which by nature have the capability of bidirectional flow limited by a software.

Rule 21 also stipulates a clause that allows Distributors to extend (almost double) all processing times depending on the amount of applications being received, as per the "Automatic Timing Extension" clause (Rule 21. F.3.c.xvi). This clause comes into effect when the number of new Interconnection Requests received by the Distributor in a given six-month period exceed fifty (50) percent of the existing active Interconnection Requests in the preceding six-month period. The distributor is consequently allowed to provide extended timelines for the next twelve (12) month period automatically.

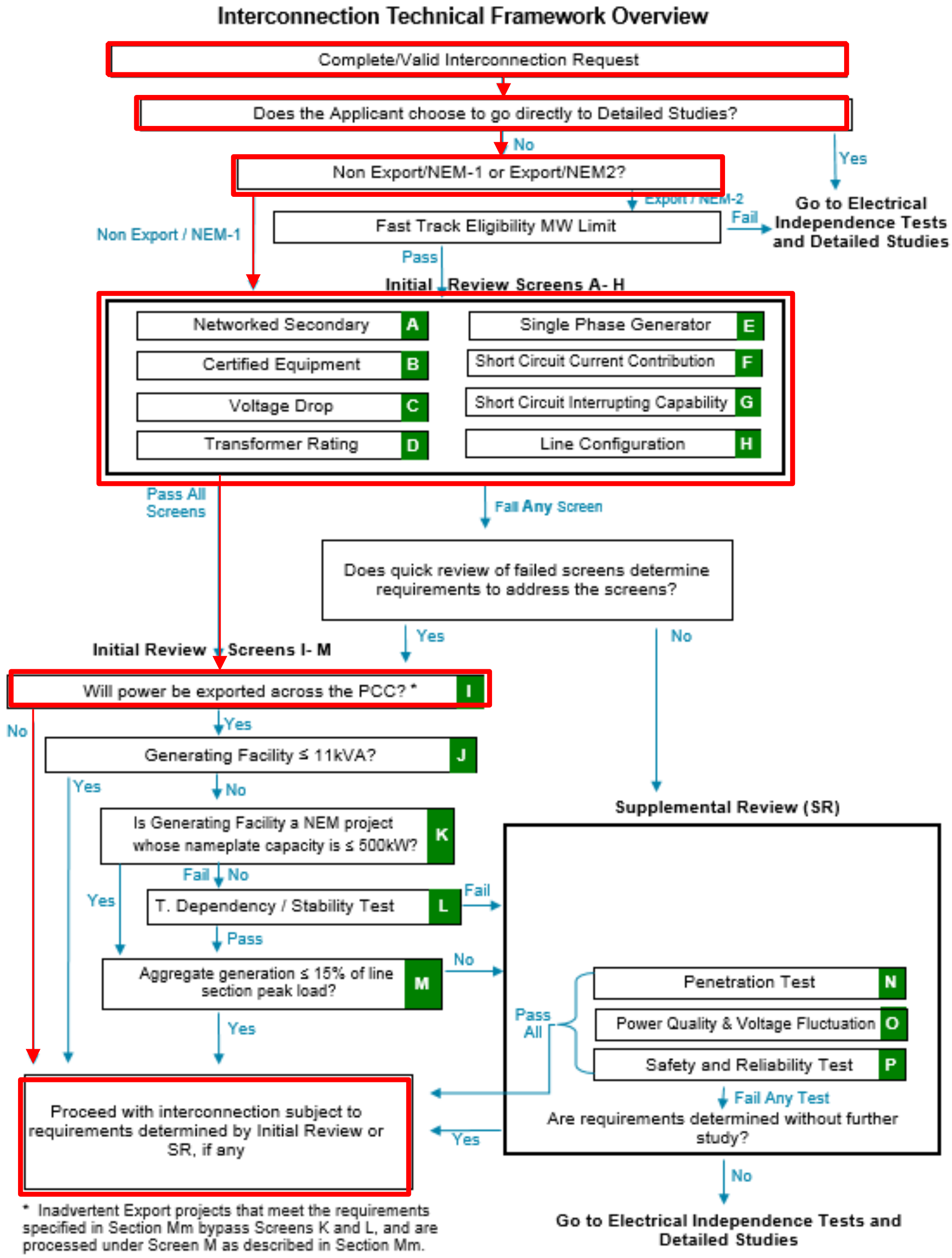


**Figure 3-7: Non-Export Fast Track Application Process Summary (Rule 21)**

## 3.4 Summary of Application Process Comparison

The most relevant application processing time in Ontario and select other jurisdictions have been analyzed and summarized in this report.

Figure 3-8 shows a bar graph comparison of stated processing time for the various LDCs studied.

Toronto Hydro, Alectra and HONI follow OEB process for distributed generators and its, overall timelines and requirements. Processing times for Ontario LDCs are generally not different for different connection types. Key characteristics such as size or if a connection requires grid upgrades may increase project time lines, but DG's are otherwise handled in the same process guidelines.

OEB DSC processes are clear for export type generators. However, the DSC does not seem to specify an explicitly defined and separate load displacement application process methodology applicable to BTM application processes. It is recommended that Ontario regulatory bodies consider how these processes can be expedited due to their non-export nature.

It must be noted that the timelines explicitly stated are specific to key deliverables and does not constitute the correspondence turn around time or time for rework that may be required in CIA, CCA, DCA approval. It is thus paramount that the application and request for these articles is done in alignment with LDC requirements to minimize the amount of rework.

Hatch had a recent and separate experience in a battery storage project connected to the 44-kV grid in Ontario. Sized at 2 MW this project involved an application to Hydro One. The CIA was issued in the second week of September. The HONI application response was provided in the last week of October. Therefore, the process took approximately 7 weeks (49 calendar days). Note that this process has yet not reached the final stage of engineering, construction, and commissioning, however, the project schedule estimates; approximately 6 months for detailed engineering, with an additional 4 months for commissioning and completion. A transfer trip was required. 1

Should rework be required by LDC, it is recommended that any critical errors are promptly conveyed to the applicant so that a change can be made, and the review can continue. The criticality of the errors or omissions should be dependent on whether review can continue with an assumed correction: for example, an obvious typo would not be critical, but an error in generator size would be critical. It is understood that projects may need to be reviewed by different LDC teams. However, in the interest of expediting the schedule, it would be beneficial to implement a preliminary review in which all teams can find any critical errors and thus to optimally allow a single rework – early in the process – to fix the critical issues. The goal here would be to limit the back-and-forth between generator and LDC that can be otherwise prevented with gated reviewing.

FERC provides a Fast Track option and thus this process is available to many US jurisdictions (under FERC) including those in Texas and California. California Rule 21 recognizes a Non-Export status which can have a more streamlined process.

In some FERC jurisdiction, the processing time for certain interconnections can be shortened if the application meets certain requirement which involves the size of the energy storage, the voltage level, and inverter type. Utilizing this Fast Track procedure, the applicant can bypass specific steps in the application process and reduce the interconnection processing time

It is recommended that the OEB and Ontario LDCs consider the ‘Fast Track’ application process under California’s Rule 21 to reduce the applications processing times for non-export inverter-based systems while ensuring that technical requirements for these systems can be met with their own specific framework

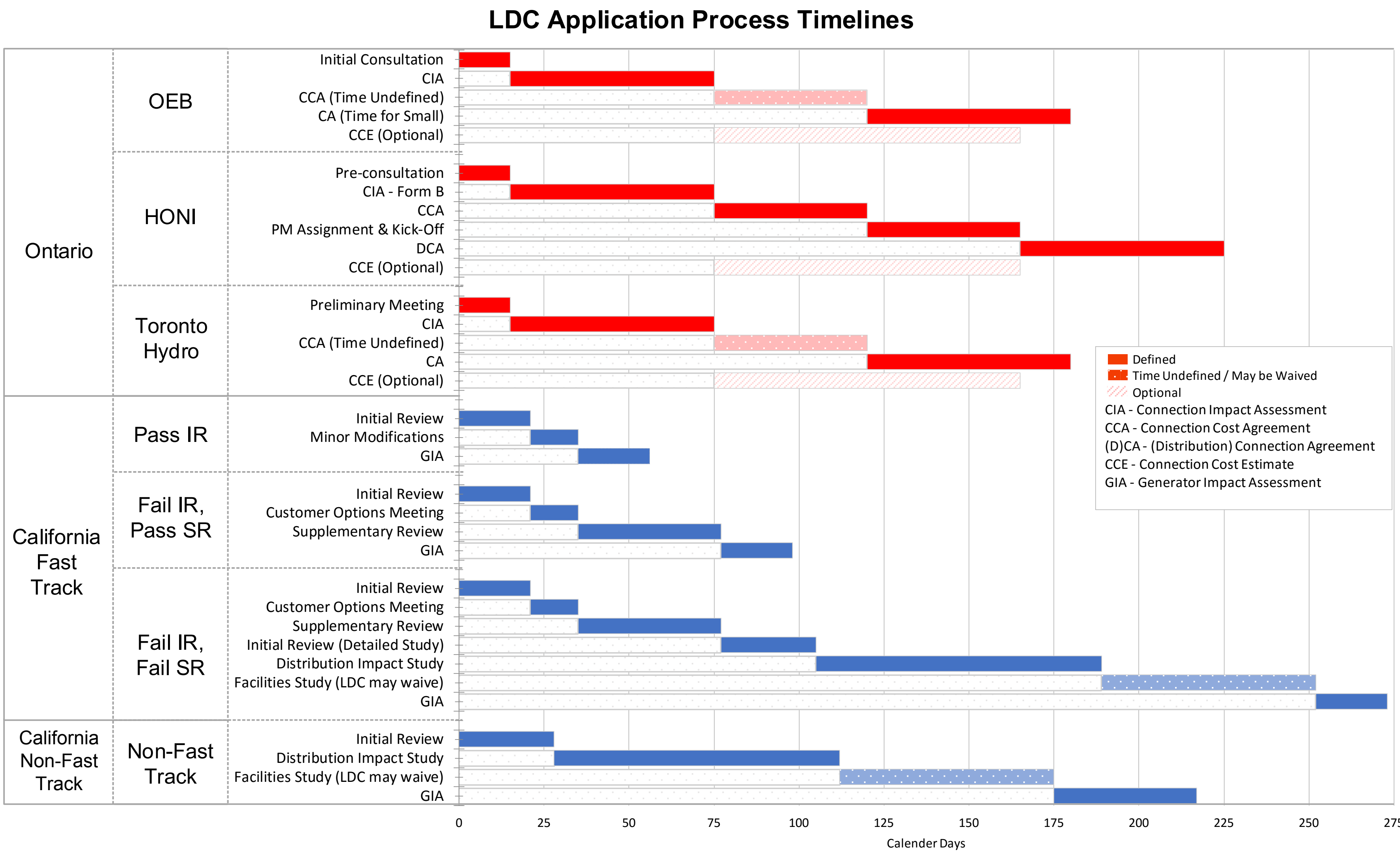


**Figure 3-8: LDC Application Process Timelines**

1. Timeline for California has been adjusted from business days to calendar days for comparison to Ontario dates.
2. IR: Initial Review, SR: Supplementary Review
3. CCE is shown as a light-colored bar at the end of CIA application as this is optional.
4. Timelines for Mid-Sized generation connections in Ontario are not well defined for the DCA and CCA processes and are said to be negotiable. It is expected that these timelines will at least match the duration shown for small connections.

# 4. Technical Requirements Review

In this Section, the interconnection technical requirements are presented for each of the selected jurisdictions. The Hatch team has reviewed and summarized the most relevant technical requirements from the LDCs in Ontario and compared with some other jurisdictions including major LDCs in California and Texas.

Enel X has identified that requirements for Direct Transfer Trip (DTT) and Monitoring are two system provisions whose costs are unknown to the applicant until the application is well underway. Therefore, an analysis was focused in these two key areas.

A summary of main technical requirements across multiple jurisdictions is provided in Table 4-1.As shown in this Table, each LDC has unique requirements for transfer trip. These requirements are mainly based on the size of the DG facility.

On the other hand, as shown in Table 4-1, monitoring is required for almost all LDCs.

**Table 4-1: Technical requirements for Ontario and other jurisdictions LDCs**

| | OEB | HONI | Toronto Hydro | Alectra | Rule 21[30] | Austin Energy | EPCOR |
|---|---|---|---|---|---|---|---|
| | | | | **Protection** | | | |
| **Direct Transfer Trip** | Provision against islanding[19] | Aggregate Gen/DG; > 1MW[9]<br>or<br>>50% minimum feeder load[9]<br>or<br>if recloser time is ≥ 1s[9] | Mid-sized generator[29] and DG capacity >50% minimum feeder load[7] | Aggregate Gen/DG; > 1MW[13]<br>or<br>>50% minimum feeder load[13]<br>or<br>if recloser time is ≥ 1s[13] | Needed if facility cannot detect faults, or islands, and cannot cease to energize in 2 s[25] | > 2MW[1,2] | If ability to export; >1MW[5] |
| **Cease to energize** | Yes (Prior to Auto-reclose)[20] | 500ms[10] | Yes[8] | 500ms[14] | Yes[26]<br>If Inverter SCCR > 0.1; 2s [25] | 10 cycles[1] If Voltage < 50% in any phase) | 600ms[4 5] |
| **Generator must deenergize prior to reclosing** | Yes[20] | Yes[9] | Yes[8] | Yes[16] | Yes[24]<br>LDC may use reclose-blocking when aggregate generation > 15% of peak load. | Yes[1] | Yes[5] |
| **Deenergize during unintended islanding** | Yes[21] | Yes[10] | Yes[8] | Yes[15] | Yes[24] | Yes[1] | Yes[4] |
| **Over/Under frequency and voltage protection** | Yes[22] | Yes[10] | Yes[8] | Yes[14] | Yes[24] | Yes[1] | Yes[4] |
| | | | | **Monitoring** | | | |
| **May be Required if** | > 250kVA[23]<br>and<br>>10MW (Facility)[23] | Yes[11]<br>(Dependent on size) | >250 kVA[28] | >100kW[18] | > 1MW<br>or<br>>250kW for <10 kV[27] (Or Deferred to meet Distribution Provider standard) [30] | >250kVA[3]<br>and<br>Not Downtown: >2MW[2] | >250kW[6] |
| **Connection status** | Yes[23] | >250 kW[12] | Yes[28] | Breaker[18] | (Deferred to meet Distribution Provider standard) [30] | Yes[3] | Yes[6] |
| **Real power output** | Yes[23] | >250 kW[12] | Yes[28] | Yes[18] | | Yes[3] | Yes[6] |
| **Reactive power output** | Yes[23] | >250 kW[12] | Yes[28] | Yes[18] | | Yes[3] | Yes[6] |
| **Voltage** | Yes[23] | >250 kW[12] | Yes[28] | Yes[18] | | Yes[3] | Yes[6] |

1. Austin Energy, Distribution Interconnection Guide for Customer-Owned Facilities less than 10 MW, Section C.8
2. Austin Energy, Distribution Interconnection Guide for Customer-Owned Facilities less than 10 MW, Section D.1.c
3. IEEE 1547.3-2007, Section 5.1 (as required by AE Distribution Interconnection Guide for Customer-Owned Facilities less than 10 MW, Section D.1.c)
4. EPCOR, Technical Guideline for The Interconnection of Distributed Energy Resources to EPCOR Distribution and Transmission Inc.'s Distribution System, Section 1.3.16
5. EPCOR, Technical Guideline for The Interconnection of Distributed Energy Resources to EPCOR Distribution and Transmission Inc.'s Distribution System, Section 1.3.17
6. EPCOR, Technical Guideline for The Interconnection of Distributed Energy Resources to EPCOR Distribution and Transmission Inc.'s Distribution System, Section 1.3.19
7. Toronto Hydro, Distribution Generation Requirements, Appendix 1(i), Section 2.3
8. Toronto Hydro, Distribution Generation Requirements, Appendix 1(i), Section 2
9. HONI, Distributed Generation Technical Interconnection Requirements – Interconnections at Voltages 50kv And Below, Section 2.3.13
10. HONI, Distributed Generation Technical Interconnection Requirements – Interconnections at Voltages 50kv And Below, Section 2.3.12
11. HONI, Distributed Generation Technical Interconnection Requirements – Interconnections at Voltages 50kv And Below, Section 2.5.1
12. HONI, Distributed Generation Technical Interconnection Requirements – Interconnections at Voltages 50kv And Below, Section 2.5.3.2, Section 2.5.3.3, Section 2.5.3.4,
13. Alectra, Embedded Generation Technical Interconnection Requirements, Section 3.3.12
14. Alectra, Embedded Generation Technical Interconnection Requirements, Section 3.3.11
15. Alectra, Embedded Generation Technical Interconnection Requirements, Section 3.4.3
16. Alectra, Commissioning Verification Form, F.2 Technical Requirements, Section 6
17. Alectra, Embedded Generation Technical Interconnection Requirements, Section 3.4.9
18. Alectra, Embedded Generation Technical Interconnection Requirements, section 3.4.9.2
19. OEB DSC 3.3.2 I
20. OEB DSC Appendix F.2 Section 6.
21. OEB DSC Appendix F.2 Section 6.1
22. OEB DSC Appendix F.2 Section 6.5
23. OEB DSC Appendix F.2 Section 9
24. PG&E Rule 21. Hh Generating Facility Design and Operating Requirements Section 1.a
25. PG&E Rule 21. Hh. Generating Facility Design and Operating Requirements Section 4
26. PG&E Rule 21. Hh Generating Facility Design and Operating Requirements Section 2.b
27. PG&E Rule 21 J.5 TELEMETERNIG
28. Toronto Hydro, Distribution Generation Requirements, Appendix 1(i), Section 1.6
29. A mid-sized generator is defined as >500kW to 10MW at < 15kV and >1MW to 10MW at >= 15kV.
30. Rule 21 was provided from PG&E in this table. SCE and SDG&E also have Rule 21 standards that may be adjusted to their respective regions.

## 4.1 Anti-Islanding Detection Overview

Based on the current standards and LDCs requirements, all DGs shall cease to energize the grid once the interconnection feeder is islanded, regardless of their size and type. This is due to safety and reliability concerns about operating as an electrical island. One of the ways to ensure islanding is prevented is through the use of transfer trip. This Section discusses islanding, various ant-islanding measures and the role of transfer trip.

### *4.1.1 Islanding*

Figure 4-1 illustrates a power system with a DG unit connected at the distribution side of the grid. During maintenance or upon a fault, certain sections of the system can become disconnected from the grid as shown below. The disconnected feeder is called an islanded system in which the grid support is lost.

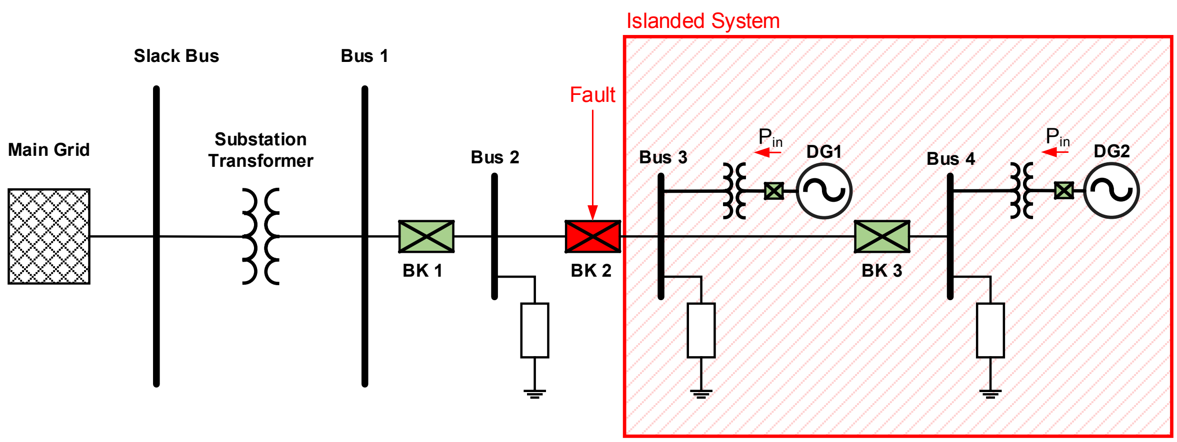


**Figure 4-1: Example of DG Islanding**

Islanding can result from the following conditions:

- A fault that is detected by the utility, and which results in opening a disconnect device, but which is not detected by the DG protection devices
- Accidental opening of the normal utility supply
- Intentional disconnect either at a point on the utility grid or at the service entrance

Although, many inverters have grid forming features that can continue to operate in islanded mode, current grid interconnection standards do not allow DGs to continue energizing the grid. This requirement is to ensure the safety of people that may be working of a grid that is energized by customer generators, concerns over viability of fault protection systems in islanded conditions, and the quality of the electrical power during islanded mode.

There are several solutions to cease system energization, covered in the following sections.

### 4.1.2 Overview of Passive and Inverter Based Islanding Detection Methods

#### 4.1.2.1 Inverter Based Detection Features

Most if not all grid connected inverters are certified to UL1741 for the US, as the accepted industry standard for this type equipment and also to CSA 107.1 for Canada. These product standards dictate requirements for the inverter equipment related to the selected components, materials, equipment failure, short circuits and a wide array of equipment rating tests, but also define the specific grid protection features with the inverters.

Although there is an ongoing evolution of the standards as new features are added to provide grid support features such low voltage ride through. The basic grid detection and protection features, based on the requirements within IEEE 1547, are:

- Over / Under Voltage
- Over / Under Frequency
- Unintentional Islanding/ Anti-islanding[8]

These features are provided within the inverter and are tested during the product certification process.

#### 4.1.2.2 Passive Islanding Detection Methods

This is fundamental islanding detection method based on the concept of monitoring the frequency and/or the voltage at the inverter terminals, at the PCC or other points within the system. In this technique the variation in the voltage and the frequency at the selected measurement point is used to determine the system condition as islanded or grid connected. The fundamental idea is that if the system is in an island condition the imbalance in generation and load will cause to local find voltage or frequency to change. This condition is typically monitored by having protection features based on the following system variables:

- Over / Under Voltage
- Over / Under Frequency

These features are normally provided within the inverter buy may also reside at other points within the system in the form of coordinated protection relays. In addition, several other passive methods exist that are less frequently used including:

- Rate of change of frequency (ROCOF) relay
- Voltage Phase Jump
- Detection of Voltage Harmonics
- Detection of Current Harmonics

[8] Terminology used in IEEE 1547 refer to unintentional islanding, which is synonymous with anti-islanding.

- Voltage based islanding detection

##### 4.1.2.3 *Minimum or Reverse Power Detection*

The reverse or minimum power protection devices are recommended by IEEE 1547.1 section 5.8 as a method of anti-islanding detection. This can be a viable option of anti-islanding detection for BTM energy storage applications. These options may be viable if there are no other potential distributed generation sources on the islanded feeder which would stay on during islanding.

It should be noted that a reverse power relay is an accepted islanding protection function according to IEEE 1547 and is acceptable according to Rule 21. It is suggested that applicability of this protection be discussed with the local LDC to evaluate if it could be applied for the BTM application

The Minimum Import Power (MIP) feature which in implemented on Enel X inverter units can offer a similar function. This function is activated to cease the battery discharge if a metered supply line unit cannot import the predefined minimum power e.g. in the case of unintentional islanding.

##### 4.1.2.4 *Active Islanding Detection*

With active islanding detection, the inverter control system uses active methods to introduce deliberate changes or disturbances to the connected circuit and then monitors the response, in order to determine if the utility grid with its stable frequency, voltage and impedance is still connected. These methods are typically proprietary to the inverter manufacturers with detection times of < 0.5 seconds under balanced islanded condition, a condition where passive methods are unable to detect. This function is necessary for all the inverter-based devices as per IEEE 1547.1, UL1741 and CSA 107.1 product standards.

#### 4.1.3 ***Direct Islanding Detection Methods***

These methods do not depend upon the inverter or passive methods to detect the islanding and are generally controlled by the utility or through communication between the utility and the DG to detect and protect against island conditions. Some of these methods include transfer trip, impedance insertion, power line signalling, and SCADA.

##### 4.1.3.1 *Direct Transfer Trip*

Figure 4-2 shows the scheme for an example direct transfer trip implementation.

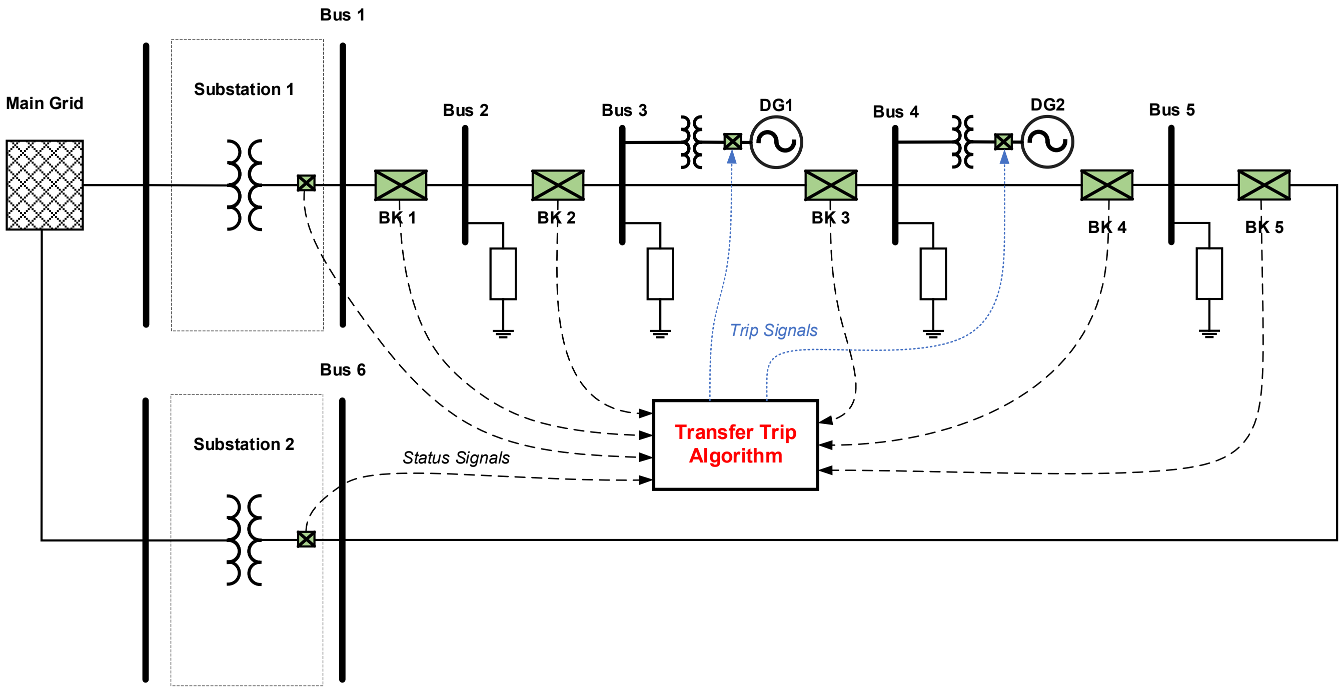


**Figure 4-2: Transfer Trip Scheme**

DTT allows the utility to remotely trip the distributed generator off line in an event of breaker openings that could leave the distributed generator in an islanding condition. The complexity of the DTT control scheme is determined by the number of reclosers and topology of the substation. Some of the factors are:

1. All circuit breakers and reclosers between the DG and the supply substation must be monitored.
2. Applicable circuit breakers and reclosers may change in time during based on feeder switching operations.
3. The reliable implementation of a transfer trip for multiple network topologies requires a central processing algorithm to determine the formation of the island
4. The algorithm needs to have the most update to date information of the system

It is also clear that a transfer trip scheme requires an extensive communication support. Absence of a signal is treated as the opening of the associated breaker. If radio coverage or telephone lines are not available, the scheme cannot be used or can be expensive to set up as compared to the project cost of small facilities.

Although a transfer trip scheme is an effective and acceptable solution among utilities, the main disadvantages are the cost and potential complexity. The cost of transfer trip in Ontario can reportedly vary from $50,000 up to $400,000 depending on the complexity. The cost of the transfer trip may have a significant impact on the business case for the project specially for small size BTM energy storage systems.

#### *4.1.3.2 Power Line Signaling Scheme*

In this method, a signal generator on the grid side generates a signal which then has to be detected by the DG. Although this method is less complex than a transfer trip scheme, the power quality and the cost associated with this technique is hard to justify if only few number of DGs are to be connected to the feeder. Figure 4-3 below shows the power line signaling concept for islanding detection.

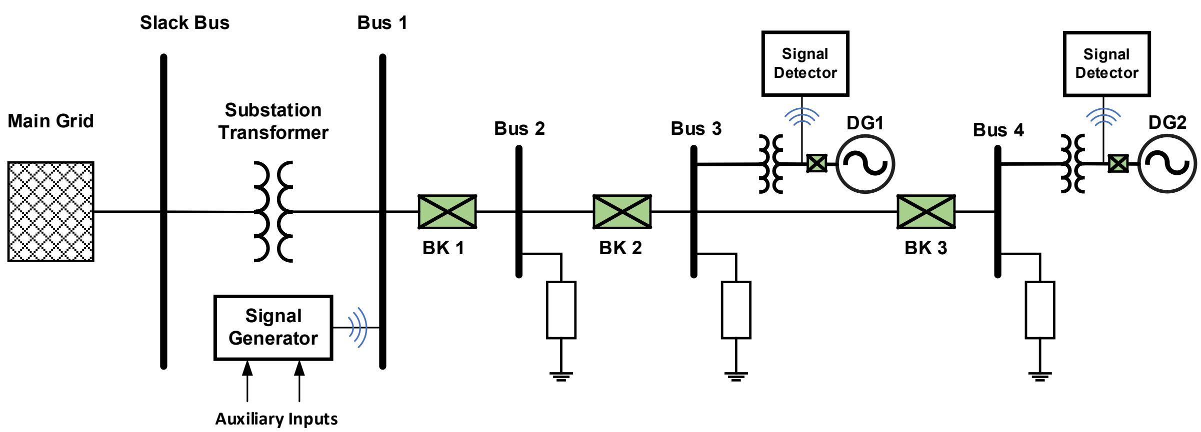


**Figure 4-3 Islanding detection based on powerline signal scheme**

Although this detection technique is a costly solution for islanding detection, it can have merit when there is a large concentration of distributed generators on a system.

## 4.2 IEEE 1547 Views on Anti-Islanding

IEEE 1547 and its associated amendments and sub-standards provide guides for the safe and reliable operation of distributed generation. The recent release of 1547 – 2018 prompts a review of the existing standards and possible changes to key items with regards to BTM storage including; cease to energise, anti-islanding and reclosing, it can be expected that changes may affect LDC's requirements as some point in the future. This section is primarily focused on collecting and providing reference points for illustration of the changes on these key issues but is not intended to provide a through review of all potential changes as a result of the updated IEEE 1547 standard.

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### *4.2.1 Cease to Energize*

Both IEEE 1547- 2018 Section 8.1 (Islanding) and IEEE 1547- 2003 Section 4.4 (Islanding) states that cease to energize is mandatory within 2 seconds of the formation of an island. However, it's also stated in the 2018 version section 8.1.2 that upon mutual agreement with the respective LDC, it's acceptable to extend the 2 seconds to 5 seconds. This change it not likely to affect projects in the near term. LDCs and utilities often require tripping times much shorter than the 2 s mark and inverter anti-islanding is often required to be below 500 ms.

### 4.2.2 *Anti-Islanding Methods*

The requirement to detect and prevent islanding according to IEEE 1547 can be met by several methods, including but not limited to transfer trip.

*IEEE 15–7 - 2003*

In IEEE 1547 – 2003 Section 4.4 footnote 12, it is stated that the requirement can be met by any of the following:

- Distributed resource (DR) aggregate capacity < 33% of the minimum load of local electric power system (EPS)
- DR is certified and able to pass the non-islanding test
- DR contains reverse or minimum power flow protection sensed between the DR connection and the PCC
- Other non-islanding means; forced frequency or voltage shifting, transfer trip, and governor and excitation controls that maintain constant power and constant power factor.

*IEEE 1547.2 – 2008*

IEEE 1547.2 – 2008 section 8.4.1 references the same requirements as highlighted in IEEE 1547 – 2003 Section 4.4 footnote 12.

IEEE 1547.2 (2008) is referenced by 1547 – 2018 as containing information on the islanding conditions; however, IEEE 1547 – 2018 states that 1547.2 is now out of date and inconsistent (See D.5.2 footnote 138 in IEEE 1547 – 2018).

*IEEE 1547.7 – 2013*

IEEE 1547.7 Section 4.1.1 (2013) discusses unintentional islanding and indicates that passive and active anti-islanding methods may not detect an island within the required time (e.g. 2 seconds) "when the DR output is close to the simultaneous or pre-fault load served within the Area EPS". This statement of being close is expected to align to the 33% requirement above.

In IEEE 1547.7 – 2013, section 7.3.2 also defines the 33% found in the earlier IEEE 1547 – 2003 version. This instance was found to be the newest reference to a 33% minimum feeder loading for anti-islanding schemes. Specifically, the aggregate DR production must be <33% of the minimum line section load for radial feeders. If this is satisfied, then (as will be described in Section 6.4 of this report) an unintended island cannot be sustained.

*IEEE 1547-2018*

IEEE 1547 – 2018 Section 8.1 states that a detection scheme that relies solely on under/over voltage and frequency trip is not considered sufficient to satisfy the detection and prevention of islanding.

#### 4.2.3 Area Reclosing

Area reclosing coordination is also required in both 2003 and 2018 versions of the standard. This is expected to ensure that reclosing events do not create synchronization or other issues in reconnecting the grid after a trip event (IEEE 1547.7 Section 4.1.1 – 2013). Appropriate steps must be taken to ensure that area EPS is not exposed to unacceptable stresses or disturbances, and for cease to energize requirements to be met. This is particularly important when considering voltage and frequency ride through requirements for DG facilities (IEEE 1547 – 2018 Section 6.4 and 6.5 and footnote 99).

### 4.3 HONI Requirements on Anti-Islanding

Anti-islanding and transfer trip requirements are important across LDCs in Ontario. HONI's large foot print in Ontario makes its requirements an important specification for LDCs and generators. The follow requirements can be found in HONI's DGTIR.

#### 4.3.1 HONI DGTIR, Section 2.3.12 Anti-Islanding Protection

This Section states that the DG facility shall disconnect from HONI's Distribution System in 500 ms. Furthermore, the facility must confirm to HONI that it cannot sustain an island longer than 500 ms.

This time requirement is also mentioned in *Section 2.3.7 Phase and Ground Fault Protection*, specifying that the total fault clearing time for a facility with transfer trip is allowed to be 500ms, compared to 200ms for facility without transfer trip or equivalent (upon approval by HONI).

The 500ms rule comes from section D.4 Types of DG Islands, as the typical automatic-reclose times for reclosers are 1.5s ~ 2s, and for feeder-breakers are 0.5s (500ms) ~ 1s. Therefore, it can be concluded that, in typical cases, as long as the islanding and/or faults can be cleared within 500ms, so the DG can be disconnected before the recloser or feeder-breaker operates.

Facilities below 500 kW may be exempted from transfer trip, with only inverter based active anti-islanding protection and anti-islanding schemes. The final scheme that a DG adopts has to be submitted to HONI for review.

#### 4.3.2 HONI DGTIR, Section 2.3.13 Transfer Trip

This Section states that a Direct Transfer trip shall be required if any of the following are true;

- the aggregate capacity of DG is 1 MW or larger.

- the aggregate capacity of the DG facility, or the aggregate DG facilities (including existing and other previous proposed facilities) is larger than 50% of the minimum feeder load or the minimum load downstream of recloser(s).
- the existing reclosing interval of the feeder breaker and /or upstream recloser is less than 1s.
- For certain systems with capacity less than 500 kW, it may be possible to use passive anti-islanding detection (Rate of Change of Frequency ROCOF and Vector Surge or Reverse Reactive Power) in lieu of transfer trip. This only applies when HONI determines risk to of islanding is sufficiently low, as an interim protection until HONI standardizes on a Transfer trip solution for systems less than 500kW. This requirement is driven from Hydro One BULLETIN B-01-DT-10-015.R3.
- It should be noted that HONI DGTIR Table 10 footnotes (15 &16) indicate that certified inverters with active anti-islanding controls and systems with a single inverter rated ≤500kW will comply with islanding protection features and may not require additional islanding protection functions.

## 4.4 Minimum Feeder Loading Requirement

Both IEEE 1547 and HONI requirements refer to a minimum feeder or area loading when referring to anti-islanding detection, however they use different thresholds based on the background are discussed in be balance of this Section.

### *4.4.1 33% threshold in IEEE 1547.7*

Based on IEEE 1547.7 Section 4.2.2, it was shown that as the pre-island loading approached three times the generation, no condition could exist to support the continued power generation.

Upon a more detailed review of the IEEE 1547, it appears that the ratio of 33% comes from the study done back in 1987 by W.B. Gish on “Ferrorresonance and Loading Relationship for DSG Installation”. The paper demonstrated that in the worst-case condition, a generator can supply as much as three (3) times its rated power output in a ferrorresonant condition. This phenomenon happens once the grid support is lost (islanding) and ferrorresonance with regards to transformer saturation occurs. This study was performed for synchronous and induction generators. It is a fair estimate that based on the short circuit contribution of the inverter-based devices and their inertia-less power injection characteristic, their maximum power supply would be less than their 3 times rating as a synchronous or induction generators. In addition, based on IEEE 1547.7, the conclusion of this paper for PV solar systems is that “If all DRs in a circuit of a distribution system are solar PV, aggregate solar PV DR production less than loads cannot support creation of an unintended island. Therefore, for solar PV DR, 100% of the minimum daytime load can be considered if all other DRs in a circuit are solar PV systems.”

In general, for BTM energy storage applications, power injection can theoretically be injected during the daytime or nighttime. However, this is unlikely for the GA reduction application and as a result, it is reasonable to treat BTM applications similar to solar PV systems by applying the criteria based on the minimum daytime load.

### 4.4.2 *50% threshold in HONI DGTIR*

This section highlights the technical background to HONI's (and other LDCs in Ontario) 50% minimum feeder loading requirement. This section is primarily focused on HONI's Distributed Generation Technical Requirements (DGTIR), and more specifically Appendix D.12

Hydro One transient stability studies have produced consistent results that have shown that in the case of 50% generator to feeder ratio, frequency and voltage deviations (declines) occur severely enough to create fast response times from passive anti-islanding protection. Specifically, according to HONI's DGTIR Appendix D.12, generator frequency declines steadily to approximate 53Hz within 1s, and voltage declines about 75% within 100 ms and recovers back to 93% within 1s.

The frequency element of passive anti-islanding protection, that is configured to align with protection settings of Section 2.3.10 of the DGTIR, would clear this fault in much less than 1 second (about 160 ms or 10 cycles at <57 Hz). Furthermore, under-voltage protection should be able to clear within 2s (2 seconds for 50 ≤ V < 88%) is set as per Section 2.3.11 of the DGTIR. However, if the generator is rated larger than 50% of feeder load, the system was not found to follow the same pattern.

HONI states that it cannot be guaranteed that DG facility anti-islanding protections will operate within required time to align with recloser operation. Insufficient availability of generic models for generators such as inverters, and static power converters, is stated as the cause of this concern.

It has to be noted that the study mentioned above only applied if the automatic recloser time is 1s or longer. As required by HONI, if it's smaller than 1s, a transfer trip is required (see section 6.2.1).

## 4.5 Evaluation of Requirements for Transfer Trip

According to Table 4-1, the transfer trip requirement is sometimes mainly justified based on the size of the DG facility, not solely the ratio between the minimum feeder load and the size of the DG. However, the size of the DG alone is not a good indicator of the need for transfer trip in some cases when a non-export generator is considered.

Table 4-2 shows cases where islanding detection system can work for various scenarios based on the feeder configuration, the generation facilities on the feeder, and power imbalance based on IEEE1547. The cases where inverter islanding detection and the minimum import power functions can and cannot detect the islanding are presented.

From this Table, one can conclude that the feeder configuration type, the ratio of DG size to minimum feeder load and the presence of other generation facilities on the feeder are more relevant criteria for deciding on the DTT requirement than the size of the DG.

**Table 4-2: Comparing DTT requirements with Anti-islanding methods**

| **Feeder Configuration Scenarios** | | | **Islanding Detection Can detect the Islanding?** | |
|---|---|---|---|---|
| Feeder Configuration | Is there any other generation on the feeder? (i.e. Load feeder) | Generation / Minimum Load Ratio <33% | Minimum Power Import Relay | Inverter with Certified Anti-Islanding |
| Non-radial | YES | N/A | May Not | N/A |
| Non-Radial | NO | N/A | YES | N/A |
| Radial | NO | YES | YES | YES |
| Radial | NO | NO | YES | May not |
| Radial | YES | YES | May Not | YES |
| Radial | YES | NO | May not | May not |

## 4.6 Most recent studies in Canada

Recently, research centers in Canada have conducted studies to illustrate the effectiveness of islanding detection techniques. Three of the such studies are presented in this Section.

### *4.6.1 CANMET Study[9]*

In this project, CANMET ENERGY in collaboration with Hydro Quebec research center (IREQ) has done several field studies on IREQ 25 kV voltage test facility to evaluate the performance of various types of passive islanding protection schemes. This work has been

[9] EL-FOULY, T. H. M., and C. Abbey. "Commercial relays field tests for passive anti-islanding protection schemes of synchronous generator based DGs." In *CIGRE Canada Conference on Power Systems, Toronto, Canada. (October 4–6, 2009). Available at http://198.103*, vol. 48, pp. 2009-181. 2009.

done to compare the response time of these relays against the upstream reclosers with regards to detection of islanding situation.

It was observed that typical under/over voltage and frequency relays have slow response times at low levels of power mismatch between feeder demand and distributed generation. This is mainly because of the absence of adequate level of voltage and frequency excursions to trigger the schemes in a reasonable time. A combination of the Rate-Of-Change-Of-Frequency (ROCOF) and the Vector Shift (VS) schemes could detect islanding of a synchronous generator for all power mismatches above 10%. The combined scheme also showed a promising detection time of below 0.3 seconds; however, the scheme failed to detect islanding for power mismatches below 10%.

### *4.6.2 ROCOF Relay Paper[10]*

The report of this project has been published in 2017 where a Canadian utility has implemented passive anti-islanding elements as an alternative to Direct Transfer Trip to interconnect a customer owned generator. This acceptance was done on an exceptional basis with many challenges. The test system has shown in Figure 4-4. The DER size is about 10 MW with inertia of H=2 sec. As discussed in the paper, although it is a single unit generation, the situation is also similar for a large amount of smaller dispersed DER. The feeder in total has about 9 MVA load.

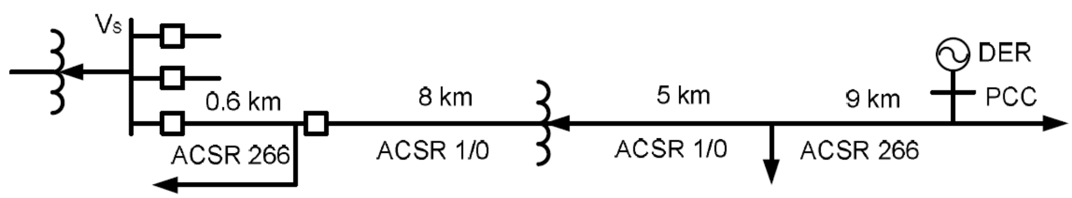


**Figure 4-4 Case study Diagram**

The Rate of Change of Frequency (ROCOF) is used in this study to detect the islanding. In frequency relays, once the frequency drops below or go above a certain limit the relay should trip within a set time. The ROCOF relays on the other hand can detect the rate of change in the frequency. During the normal operation and in presence of the grid, the load and generation are matched with the continuous support from the grid. Hence, the frequency stays within the acceptable limit (almost constant at 60 Hz). Once the network or the feeder becomes islanded, the load and generation mismatch will cause deviation in the frequency. It

[10] Nassif, Alexandre, and Colin Madsen. "A real case application of ROCOF and vector surge relays for anti-islanding protection of distributed energy resources." In *Electrical Power and Energy Conference (EPEC), 2017 IEEE*, pp. 1-5. IEEE, 2017.

is clear that the sudden increase in the generation and load mismatch results in the faster frequency deviation.

The relay was successfully installed at the PCC and has been operating as intended for over one year.

### *4.6.3 Kinetrics Report[11]*

The study was done by Kinetrics to evaluate the HONI anti-islanding requirements. The summary of the findings is as follow:

a. The 7% to 10% of the feeder maximum loading were stated as reasonable criteria for determining safe and reliable detection of the islanding situations. Note that HONI defines the minimum loading to be 20% of the maximum loading of the feeder. Hence, 7% to 10% of the maximum feeder loading can be interpreted as 33% to 50% feeder minimum loading requirement.

b. It was recommended that since the inverter-based generation units do not have the same behaviour as synchronous and induction generators, further studies should be considered to better identify gaps in the present LDC requirements and the inverter CSA/UL testing protocols.

## 4.7 Monitoring Requirements

As shown in Table 4-1, DER monitoring facilities for DGs voltage, real power, and reactive power are required for almost all LDCs and according to prevailing standards based on certain size criteria. However, there does not appear to be any significant published data the describes the specific logic behind these requirements. However, there are a number of reasons that explain why monitoring of DG data including the BTM energy storage systems is important for utilities:

1. The LDCs require to have information of the system loading for their planning and scheduling purposes. The amount of load that has been supported by the energy storage would not be known to the LDCs if the energy storage power output is not monitored.
2. The LDCs need to know the feeder loading before re-energizing the system after a contingency tripping. If for example due to an anti-islanding or a transfer trip operation the DER or BTM energy storage becomes off line, LDCs will not be able to plan properly for energization as they have not enough knowledge of the load upon energization. Here is an example:
    a. The system has 10 MW load
    b. 5 MW of the load is supported by DG/DGs on the system

[11] Wrathall, Nicolas, Stephen Cress, and Yury Tsimberg. "Technical review of hydro one's anti-islanding criteria for micro-fit PV generators." *Kinetrics Inc* 800 (2011).

c. Due to a fault the system is disconnected (per islanding requirement, the energy DGs have to be disconnected as well)

d. During the restoration the LDC expects 5 MW load on the feeder while in fact the actual load is 10 MW.

The actual generation to load ratio to trigger the monitoring requirement has not been defined in standards. However, LDCs have requirements which sometimes are dependent on the size of the facility. For example, in Rule 21, telemetering may be required if the generating facility is greater than 1 MW or if the generation facility is greater than 250 kW for voltage level below 10 kV.

## 4.8 Summary of Technical Requirement Comparison

This report reviews the need for transfer trip and compared its operation with anti-islanding detection techniques. Most relevant standards, recent and peer-reviewed papers, and LDC's requirements were considered in this regard. In addition, monitoring system requirements have been analyzed. The findings are as follow:

- The LDCs transfer trip requirements are mainly justified based on the size of the DG (in this case energy storage facility).
- Standards and studies indicated that the feeder configuration, presence of other generation sources on the feeder and the ratio between DG generation and the minimum feeder load are the main indicators for islanding detection functionality
- The cost of the transfer trip is mainly affected by the number of monitored switching devices, power supply system configuration, and topology and the overall complexity of the control scheme. The wide range of potential cost of implementing the direct transfer trip has a negative impact on the project cost estimation and planning. It is recommended that LDCs place priority on evaluating of the need for DTT, assess the complexity and provide an approximate cost for a DTT scheme as early as possible in the assessment process to allow developers to better make go-no go decisions.
- It is shown that the monitoring equipment are required for LDC operation, reenergization, and planning. It is also recommended that more studies to be done to evaluate the monitoring need with regards to the ratio between DG facility and minimum feeder loading.
- For many cases, depending on feeder configuration, and where the BTM energy storage source is less than 33% of the feeder minimum load, the anti-islanding features of certified inverters together with certified minimum import power relays can be a viable form of anti-islanding protection as an alternative to direct transfer trip. These factors seem to be more relevant to determination of the need for a transfer trip than simply the size of the energy storage facility.

- Recent studies in Canada have tested alternates to direct transfer trip and have shown cases where they can be implemented successfully even with synchronous generators with a large relative size compared to the feeder load.

# 5. Analysis of Current Enel X Projects Time Lines and Technical Requirements

Enel X is implementing a 520 kW BTM energy storage for its client, Algoma, and in this process, has gone through an application process with HONI. Hatch was provided with several email correspondence between Enel X and its team and HONI. Hatch was also previously provided with the timeline chart in Figure 5-1 showing the overall connection time process. The provided information including Emails and applications from Enel X are presented in Appendix A.

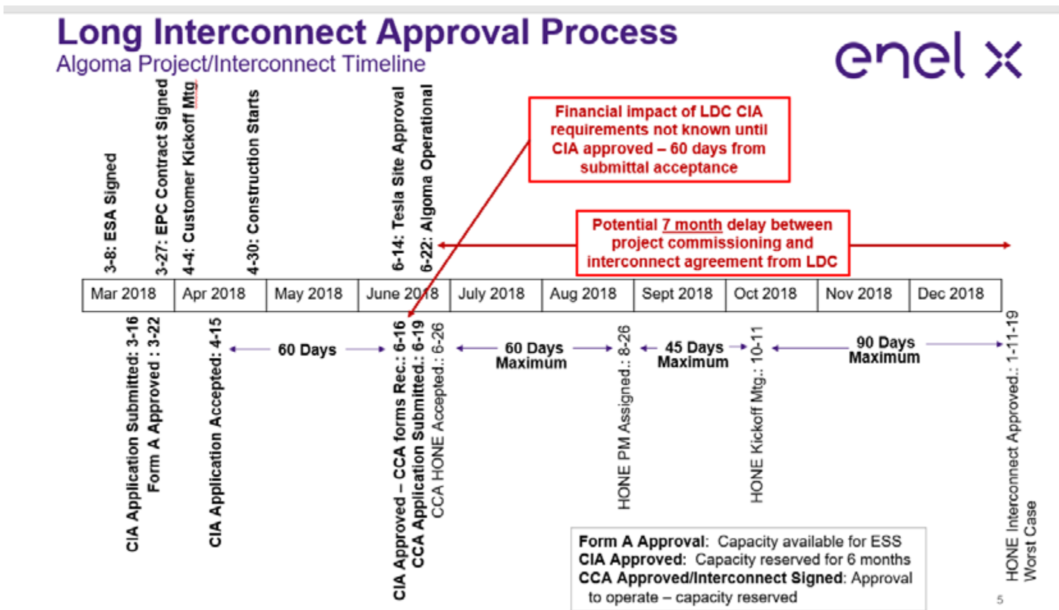


**Figure 5-1: Long Interconnect Approval (from Enel X Presentation)**

Table 5-1 summarizes the comparison between the actual processing times and the specific technical requirements in this case against the LDC's maximum stated processing time and stated requirements.

Enel X has provided their email correspondence with HONI from March 22, 2018 to November 30, 2018. However, specific records of pre-consultation submission, CIA submission, CIA Approval, and other major email receipts were not found. Therefore, for these dates the data in provided in Figure 5-1 as used.

**Table 5-1: Analysis of Current Enel X Projects, Case #1**

| Processing time |
|---|

| HONI Stated Processing Times | | Actual Processing Times | | |
|---|---|---|---|---|
| Milestone | HONI Estimated Turnaround | Information received from Enel X? | Date[2] (Submission – Approval) [MM/DD/YYYY] | Actual Turnaround Time [days] |
| Pre-consultation (optional) | 15 days | Partially | Not Known | Not Known |
| CIA | 60 days | No | 4/15/2018 - 6/16/2018[3] | 62[3] |
| CCE (Optional) | 90 days | N/A | N/A | N/A |
| CCA | 45 days[1] | Yes | 6/19/2018 - 8/8/2018 | 50 |
| PM Assignment and Kick-off | Kick-off Meeting 45 days after CCA | Yes | Kick-off meeting Sept 21 | DCA Pending; Kick-off meeting happened 43 days after CCA |
| DCA | 60+ days | Yes | DCA submitted Nov 5th (Hard copy received by HONI) | Not received (last email Jan 9 which is 65 days) |

1. According to *Connection Process for Distribution-connected Generators under FIT* by HONI, "6 months from the time CIA is completed the Proponent must submit the CCA application to us 45 days in advance of the 6-month deadline to allow for processing and completion" it's assumed the CCA takes at least 45 days.
2. The dates provided in this table are based on email correspondence provided to Hatch, unless otherwise specified.
3. The emails regarding the exact date of CIA submission and approval were not determined from emails provided to Hatch. However, through email correspondence it can be assumed that submission and approvals fall close to ranges specified Enel X's summarized timeline in Figure 5-1. These dates from this figure are thus used in place of explicit email dates.

Some further details on Enel X and HONI interaction relate to requests for exemptions and discussions of a 'Fast Track' process. This arrangement would permit Enel X to connect temporarily by satisfying certain requirements (ESA, DCA, SLD approved by metering and settlements). The outstanding requirements (SLD approved by protections, etc.) would have to be approved within this temporary connection period of three months to remain in service. From the most recent communications known at the time of this report, Enel X has submitted the three requirements of the 'Fast Track' process, and is awaiting DCA execution from HONI.

The project status as of 16 January is as follows: 1

- Revise SLD & protection philosophy to come in compliance with HONI direction. (Ready for EnelX review Jan 18 latest) – submit to HONI – due Jan 18
- HONI review of SLD & protection philosophy & confirm acceptance – due Jan 23
- EPC complete COVER section 2 testing and submit to HONI (requires relay & breaker to be installed): due April 3
- HONI approves COVER section 2 & grants approval to close switch for PF testing: due April 5

- EPC complete COVER section 3: due April 3
- HONI approves COVER section 3 & grants authorization to generate: April 17

Based on provided details of the Enel X and HONI interactions the following points are made:

- The DTT and monitoring requirements were consistent with the HONI DGTIR.
- The processing time for the CIA was found to be 2 days longer than specified the timeline provided by HONI on their website and as summarized in section 5.2.1. This is with the assumed timeline provided.
- A project manager was assigned 27 days after the CCA is executed and the first kick-off meeting with HONI was held 43 days after the CCA. This aligns with Hydro One definition of 45 days to kick-off.
- According to the emails, the initial SLD submission happened on Sept 26, 2018. HONI's review responses were found on three separate dates as follows:
  - Oct 1st: HONI's protection officers commented (5 days after the SLD was submitted),
  - Oct 19th: HONI's metering officers commented (23 days after SLD was submitted),
  - Oct 24th: HONI's settlement officers commented (29 days after SLD was submitted).
- HONI review process of the detailed engineering deliverable is done in tandem with several different teams. Each team was found to provide review at different times. Hatch believes that receiving critical comments as soon as possible would be most beneficial for the progress of the connection. Hatch believes comments provided that are not critical, in that they do not require a pause of review until corrected, can be provided as soon as available by each team separately.

# 6. Discussion with Ontario LDCs

Hatch met with a representative of Toronto Hydro Electricity Services (THES) to discuss their processes for BTM energy storage within their jurisdiction.

Hatch has also attempted reaching HONI representatives for a similar discussion. However, no response has been received from HONI to the Hatch's request.

The following sections outline the of discussion between Hatch and LDCs that responded.

## 6.1 Notes from Discussions with THES

### *6.1.1 General Discussion on Interconnection Process*

Leading with a high-level discussion on Toronto Hydro's process, the specific challenges faced by Toronto Hydro as a utility were outlined. THES targets to have a highly reliable system and this affects their interconnection process. Having both a high volume and density of customers paired with old infrastructure makes Toronto a unique jurisdiction from other LDCs in Ontario.

It was stated that Toronto Hydro has a dedicated team of 15 engineers dedicated towards generation planning and system studies, which includes reviewing Distributed Energy Resource (DER) applications for customers.

### *6.1.2 Pre-assessment Form*

The Toronto Hydro process involves a pre-assessment form for DER projects, regardless if they are before or behind the meter.

It was recommended that each client complete the pre-assessment form for each project. This process is offered free of charge and takes 15 days. The pre-assessment includes:

- Assessment of the proposed installation based on the five screening ratios.
- Average minimum load (based on previous 5 years), and the short circuit level at the point of interconnection.
- Recommendations to the client on how to meet interconnection requirements.

The intent of this process is to ensure the client submits the correct documentation to meet the requirements moving forward. Toronto Hydro describes its processing times with the assumption that the application provided has the proper, complete documentation, with professional quality by qualified personnel.

### *6.1.3 Application Process*

Toronto Hydro uses the timeline of the “FIT” program for moving through the actual application process itself. Sizing of the client ESS has an important impact on both time and cost of the process. For larger capacities (above 1MW), Toronto Hydro must consult with greater entities (Hydro One, IESO) to assess the greater impact on the grid. The reports generated from these consultations consist of:

- Connection Impact Assessment (CIA)
- Transmission Impact Assessment (TIA)
- System Impact Assessment (SIA)

Toronto Hydro emphasized that regardless of the DER sizing, they are the main point of contact throughout the entire application process regardless of the involvement from other entities. From Hatch’s understanding of discussions on this topic, an outline of sizing impacts on cost, timeline, and organizational scope can be seen in Table 6-1 below.

**Table 6-1: Toronto Hydro DER Sizing Schedule & Cost Impact**

| Size | Procedures | Timeline | Cost |
|---|---|---|---|
| Under 2MW | Toronto Hydro CIA<br>(Above 1MW, HONI is notified) | 60 days | Up to 10kW: $500<br>10kW to 500kW: $2.5k<br>500kW to 2MW: $6k |

| | | | |
|---|---|---|---|
| 2MW-10MW | Toronto Hydro CIA<br>Hydro One CIA | 120 days<br>(60 TH + 60 HONI) | $15k CIA (THES)<br>+ $15k CIA (HONI)<br>= $30k |
| >10MW | Toronto Hydro CIA<br>Hydro One CIA<br>Hydro One TIA<br>IESO SIA | 180 days<br>(60 TH + 60 HONI + 60 IESO) | $15k CIA (THES)<br>+ $15k CIA (HONI)<br>+ $15k TIA (HONI)<br>+ $20k SIA (IESO)<br>= $65k |

In this process, THES will complete a full CYME analysis of the client connection based on client equipment information.

#### 6.1.4 *Contrast to Other Jurisdictions*

Hatch brought up the interconnection process of other jurisdictions for comparison to the requirements of THES.

In response to fast track options, the concern was raised that the connection of many PV inverters has caused grid fragility for many LDCs. It is unclear how the implementation of a fast track program for BTM energy storage explicitly ties into these problems. In fact, maintaining the program with an emphasis on accepting ESS projects would help mitigate the problems faced by utilities. Added ESS to the grid could help flatten the demand curve by storing or releasing energy at appropriate times throughout the day, addressing issues locally at peak contributors.

#### 6.1.5 *Direct Transfer Trip Discussion*

The requirement of a transfer trip connection was brought up in discussion by Hatch. It was noted how the DTT connection is often an unexpected high cost for customers with prior experience in other jurisdictions.

THES reiterated that the requirement ties back to their concerns about safety and grid stability and that the developers need to budget for transfer trip installation in their DER projects. Sometimes developers build a business case for a site based on other jurisdictions, failing to account for how Ontario's differences can affect their budgets. While this may be true, it is seen that these costs can vary within a wide range and in some cases the cost may be finalized in the further stages of the interconnection process. If these costs result to be on the higher end, can cause a project to become unfeasible after a customer has already invested into a project. By providing interconnection cost estimates earlier in the project cycle, LDCs could greatly reduce the risk brought on by customers pursuing these projects. This is especially true for smaller DER installations, where these costs could be the largest expense of the project.

#### 6.1.6 *Potential Schedule Improvements*

Toronto Hydro acknowledged how improvements to inverter technologies may change the necessity of various interconnection requirements in the future. They emphasised a willingness to work with contractors on integrating new technologies, but not without a due process of testing. Toronto Hydro expressed that they would need to verify performance of new technologies in the context of their own grid before allowing installation.

Within the current framework, the Toronto Hydro rep outlined that the equivalent of a 'Fast Track' interconnection program for the utility is to ensure that all documents upon submittal are correct and complete. They noted that communication delays between parties for missing information is often the culprit for extending the duration of a project.

# 7. Conclusions

This report has provided a review of the BTM Energy Storage interconnection application processing time and requirements in Ontario and other jurisdictions. In addition, several technical requirements have been reviewed in detail.

The summary of Hatch findings can be found in Sections 3.4 and 4.8. There are also recommendations made in the preceding sections in regards to expediting the process for integration of BTM inverter-based non-export systems.

# 8. References

**Alberta EPCOR**:

Application Process:

*[1]"Apply for Micro-Generation | EPCOR Power", Epcor.com, 2018. [Online]. Available:* *https://www.epcor.com/products-services/power/micro-generation/Pages/micro-generation-application.aspx. [Accessed: 12- Nov- 2018].*

Technical Requirement:

*[4] Austinenergy.com, 2018. [Online]. Available:* https://austinenergy.com/wcm/connect/23c5f881-73da-4064-b1bc-a7a428c9eebb/austin-energy-interconnection-guide.pdf?MOD=AJPERES&CVID=maiPEYX *[Accessed: 12- Nov- 2018].*

**Oncor:**

Application Process:

[5] *Oncor Application for Interconnection of Distributed Generation, Certified Systems*. Oncor, 2018.

[6] "Frequently Asked Questions – Renewable, Solar and More", *Askoncor.com*, 2018. [Online]. Available: http://www.askoncor.com/EN/Pages/FAQs/Category.aspx?q=Renewable,%20Solar%20and%20More. [Accessed: 12- Nov- 2018].

**Austin Energy:**

Technical Requirement:

[7] *Austinenergy.com, 2018. [Online]. Available:* https://austinenergy.com/wcm/connect/23c5f881-73da-4064-b1bc-a7a428c9eebb/austin-energy-interconnection-guide.pdf?MOD=AJPERES&CVID=maiPEYX *[Accessed: 12- Nov- 2018].*

[8] *IEEE Std. 1547.3-2007, IEEE Guide for Monitoring, Information Exchange, and Control of Distributed Resources Interconnected with Electric Power Systems*. IEEE, 2018.

**Rule 21**

[9] https://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_21.pdf

[10] https://www.sce.com/NR/sc3/tm2/pdf/Rule21_1.pdf

[11] http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-RULES_ERULE21.pdf

**Ontario Energy Board (OEB)**:

Distribution System Code:

*[12]"Ontario Energy Board Distribution System Code", oeb.ca, March 15, 2018. [Online]. Available:* https://www.oeb.ca/oeb/_Documents/Regulatory/Distribution_System_Code.pdf. *[Accessed: 12- Nov- 2018].*

*Distribution System Code Appendix F*

*[13]"APPENDIX F Process and technical Requirements for Connection Embedded Generation Facilities", oeb.ca. [Online]. Available:* https://www.oeb.ca/documents/cases/EB-2005-0447/appendixf_201206.pdf. *[Accessed: 12- Nov- 2018].*

# Appendix A:
# Email Correspondence for Enel X Cases

Client: Algoma #39500

LDC: HONI

Size: 520kW

Missing materials:

- More CIA related emails and documents

| Timeline | Milestone | Processing Time by HONI | Actual Processing Time (Time between two milestones) | Cumulated Days | Notes |
|---|---|---|---|---|---|
| unknown | Pre-FIT Consultation Submission | | | | |
| 3/16/2018 | CIA Submitted[1] | | | | |
| 3/22/2018 | Pre-FIT Consultation Response | 15d | 7 | 7 | |
| 4/11/2018 | Connection Impact Assessment discussion | 60d | 20 | 26 | HONI confirmed application received and under review. Expect 2 months |
| 4/15/2018 | CIA accepted[1] | | 4 | 30 | |
| 4/30/2018 | Construction starts[1] | | 15 | 45 | |
| 6/16/2018 | CIA Approved[1] | | 47 | 92 | |
| 6/19/2018 | Connection Cost Agreement (CCA) submission | | 3 | 95 | |
| 8/8/2018 | Connection Cost Agreement (CCA) Response | Assume 45 days | 50 | 146 | |
| 9/5/2018 | PM assigned | 21 – 45 days | 27 | 173 | |
| 9/17/2018 | DCA form submission | | 12 | 185 | |
| 9/21/2018 | Kick-off meeting on site | | 4 | 189 | |

| | | | | | |
|---|---|---|---|---|---|
| 9/26/2018 | SLD submitted | | 5 | 194 | |
| 10/1/2018 | Protection officer's comments on the SLD | | 5 | 200 | |
| 10/19/2018 | Metering officers comments | | 18 | 218 | |
| 10/25/2018 | Meeting | | 5 | 223 | Fast track agreed by HONI: temporary connection allowed |
| 11/2/2018 | SLD submitted | | 8 | 231 | |
| 11/27/2018 | ESA Authorization, Protection Philosophy, MIP submitted | | 25 | 256 | |
| 11/29/2018 | Meeting | | 2 | 258 | Metering and Settlement approved SLD. Protection pending; DCA pending approval; |
| 12/17/2018 | Meeting Comments Addressed | | 18 | 276 | Protection Philosophy, Updated SLD, and Inverter Specifications submitted |
| 12/18/2018 | Additional exemptions requested for certain TIR clauses | | 1 | 277 | |
| 1/07/2018 | HONI Response to TIR exemptions | | 20 | 297 | Additional SLD comments, TIR exemptions not provided |

**1. Refers to items not explicitly found and thus assumed from Enel X provided timeline**

Further details of most recent communications known at the time of this report can be seen below.

- Enel X requested clarification and certain exemption of protection comments and customer documentation on Oct 3rd and follow up on Oct 9th. HONI rejected exemption of customer documentation.
- Enel X requests clarification and exemption of protection comments on Oct 16th and Oct 24th. Meeting scheduled Oct 25th with Enel X and HONI to discuss outstanding items and possibility of "Fast Track".

- Enel X and HONI agreed to a “Fast Track” process shortly after this review. Hatch’s understanding of the discussed “Fast Track” is that a temporary connection (valid for 3 months) is allowed without SCADA, but all connection requirements have to be met within three months timeline, otherwise the DG facility will be disconnected.
- Nov 2nd: SLD and ESA documentation required for the “Fast Track” process provided by Enel X to HONI.
- Nov 5th: HONI metering officer approval is received, ESA is approved, DCA remains for initiation of “Fast Track”. ESA however will expire prior to connection (Nov 22nd) and thus Enel X must re submit for ESA extension.
- Nov 7th: HONI looks to continue protection documentation updates which would need to be finished prior to the end of the temporary connection (3 months). Outstanding item for Fast Track is waiting for HONI to execute DCA
- Nov 13th – Nov 20th: Enel X and HONI discuss possible exemptions from TIR for protections
- Nov 27th: Renewed ESA provided to HONI by Enel X, and protection philosophy
- Nov 29th: HONI and Enel X meet to discuss outstanding items and tasks

# Appendix B: Glossary of Terms

- BTM – Behind the Meter
- CAISO – California Independent System Operator
- CCA – Connection Cost Agreement (from HONI)
- CCE – Connection Cost Estimate (from HONI)
- CIA – Connection Impact Assessment
- DAT – Distribution Availability Test
- DCA – Distribution Connection Agreement (from HONI)
- DER – Distributed Energy Resource
- DR – Distributed Resource
- DSC – Distributed Systems Code (from OEB)
- DTCA – Detailed Technical Connection Assessment (from HONI)
- DTT – Direct Transfer Trip
- EPS – Electric Power System
- ERCOT – Electric Reliability Council of Texas
- ESA – Electric Safety Authority
- ESS – Energy Storage System
- FERC – Federal Energy Regulatory Commission
- FIT – Feed-in Tariff
- GA- Global Adjustment (IESO)
- HONI – Hydro One Networks Incorporated
- IESO – Independent Energy System Operator
- LDC – Local Distribution Company
- NERC – North American Electric Reliability Corporation
- NRTL- Nationally Recognized Test Laboratory
- OEB – Ontario Energy Board
- OPA – Ontario Power Authority (Historical)
- SCC – Short Circuit Capacity
- SGIP – Small Generator Interconnection Procedures (from FERC)

- SIA – System Impact Assessment
- TAT – Transmission Availability Test
- THES – Toronto Hydro-Electricity System Limited
- TIA – Transmission Impact Assessment
- TIR (DGTIR) – Technical Interconnection Requirements
- UL- Underwriters Laboratory