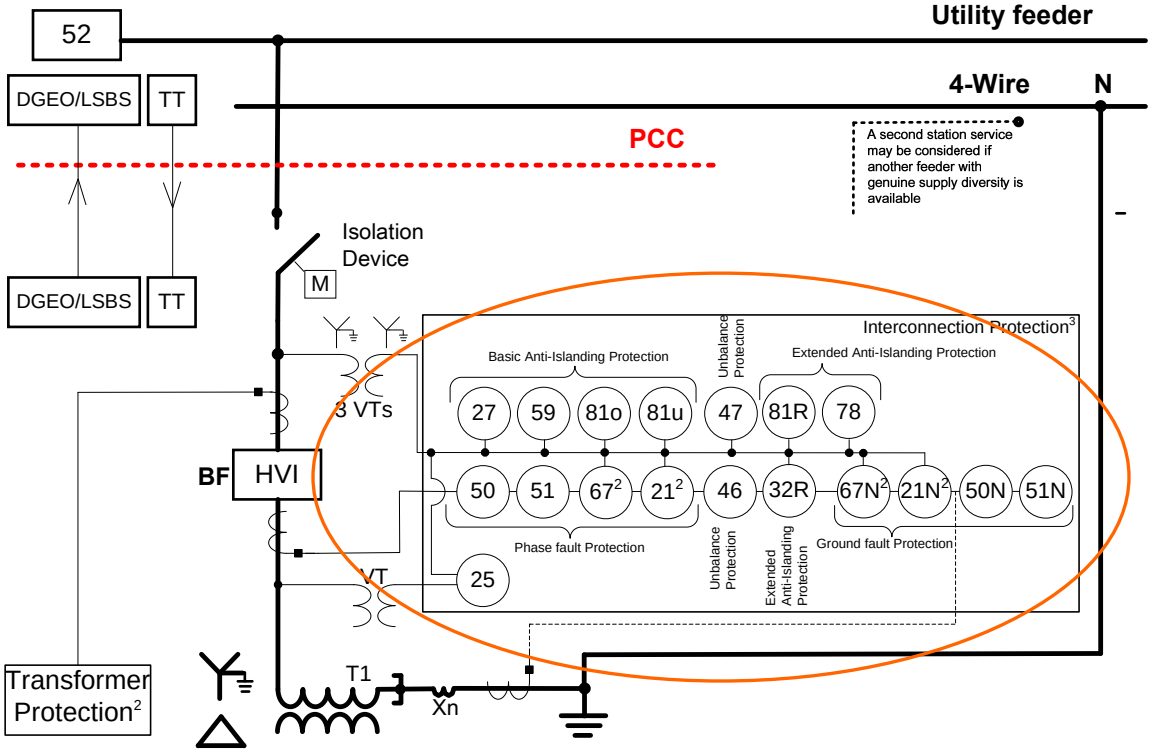
1.0 Why does Hydro One prefer a dedicated inter-connection protection?

The inter-connection protection at a DG facility refers to the tele-protection, phase and ground fault protection for faults on distribution feeders, unbalance protection and anti-islanding protection. A typical 1-line schematic is shown below and there are numerous elements that are required to be included in this protection as per the TIR. Implementing all these protections in various equipment is not an easy task. Therefore, the provision of a dedicated protective device for this purpose would make the design simpler and more reliable. Also, this would make the review of the proponent's design and settings (required per section 2.3.1 of the TIR) easier and independent from other protections that would not impact the Hydro One system. Another benefit of this independent protection is the capability of recording events and disturbances when faults occur on the system, which may impact the Hydro One system.



2.0 Why can't a combination of a fuse plus HVI (in configurations where an HVI, plus motorized DS is required by the TIR) exempt the proponent from providing the BF protection and consequently the motorized DS?

The HV fuse, which had been shown in the previous version of the TIR, was intended as an optional device to cater to the consequences of opening the motorized disconnecting switch, if the proponent had safety concerns with regards to such an operation (section 2.3.4, item iv). This fuse was not intended to replace the breaker failure (BF) protection in cases where an HVI was required (or the motorized DS itself). In order to eliminate such mis-interpretations, it was decided not to show such optional items in the TIR single line diagrams. As per the referenced clause in the TIR, the proponent still has the option to add the HV fuse (in addition to the motorized DS, HVI and its required breaker failure protection).

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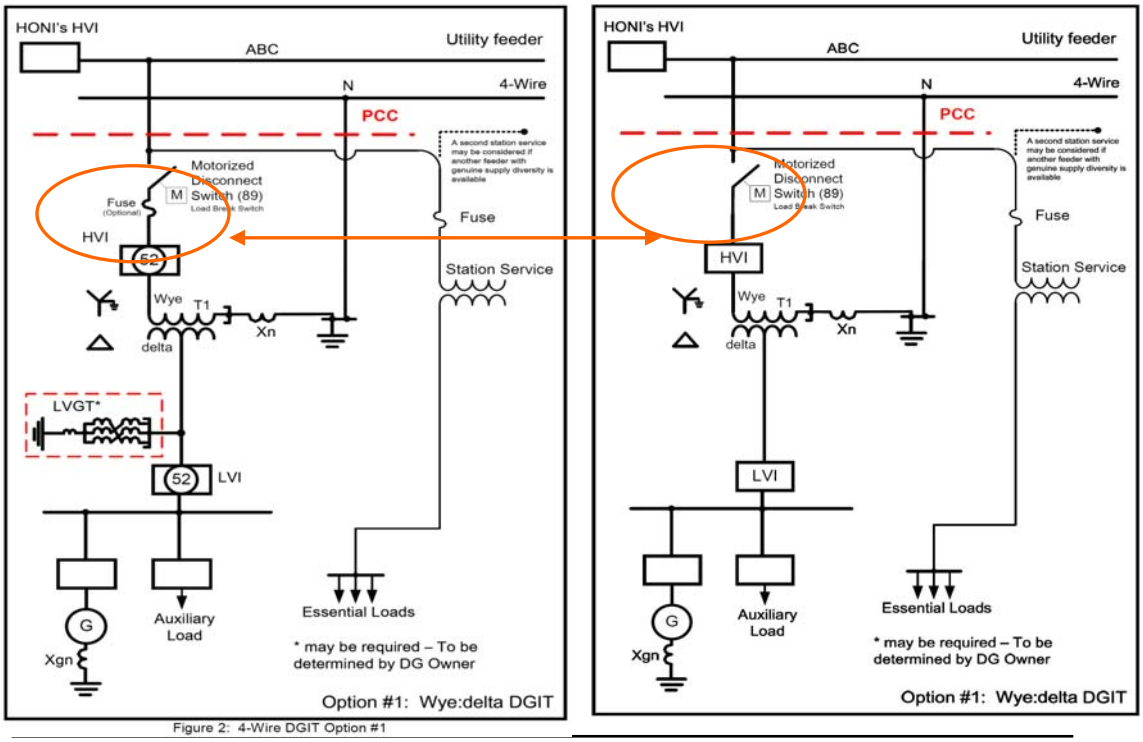

Figure 2: 4-Wire DGIT Option #1

3.0 If all the protection elements in Table 10 are not required, how can the proponent choose the acceptable protection elements that are required by Hydro One?

Table 10 has been revised to reflect Hydro One inter-connection requirements with more clarity. In this table, each of the required protection elements for various types of generators are identified and underneath some of these elements, the alternative protective element has been indicated. Also, for further description of these protections, relevant sections have to be referenced, as shown in last column.

Table 10: Typical Interconnection Protections for Three Phase DGs

Function Requirement	Protection Element function	Device # [1]	Synchronous	Induction	Inverter [2]	Section
Basic Anti-Islanding	Over-Voltage Trip	59	Required	Required	Required	2.3.11, 2.3.12 iii)
	Under-Voltage Trip	27	Required	Required	Required	
	Over-Frequency Trip	81O	Required	Required	Required	2.3.10, 2.3.12 iii)
	Under-Frequency Trip	81U	Required	Required	Required	
Tele-protections	Transfer Trip Receive	TTR	as per Section	as per Section	as per Section	2.3.13
	DGEO/LSBS	DGEO	as per Section	as per Section	as per Section	2.3.14
Other passive Anti-islanding (Application Specific)	Rate of Change of Frequency (ROCOF)	81R	≤ 500 kW	≤ 500 kW	Not required [3]	2.3.12 iv)
	Vector Surge	78	≤ 500 kW	≤ 500 kW	Not required [3]	
	Directional Reactive Power Relay [4]	32R	≤ 500 kW [4]	≤ 500 kW [4]	Not required [3]	
Phase Fault Protection	Phase Over-current	50	Required	Required	Required	2.3.7
	Phase Inverse Timed Over-current [5]	51	See Note [5]	See Note [5]	See Note [5]	
	Voltage Controlled Over-current [5, 6]	51V	See Notes [5, 6]	See Notes [5, 6]	See Notes [5, 6]	
	Directional Phase Over-current [7]	67	Required [7]	Required [7]	Required [7]	
	Phase Distance [6, 7]	21	See Notes [6, 7]	See Notes [6, 7]	See Notes [6, 7]	
Ground Fault Protection	Neutral Over-current	50N	Required	Required	Required	
	Neutral Inverse Timed Over-current	51N	See Note [5]	See Note [5]	See Note [5]	
	Directional Neutral Over-current [7]	67N	Required [7]	Required [7]	Required [7]	
	Ground Distance [6, 7]	21N	See Notes [6, 7]	See Notes [6, 7]	See Notes [6, 7]	
	Ground Overvoltage [8]	59G	Required [8]	Required [8]	Required [8]	
Unbalance	Negative Sequence Current	46	as per Section	as per Section	as per Section	2.3.8
	Negative Sequence Voltage	47	as per Section	as per Section	as per Section	
Ferro-resonance	Peak detecting Overvoltage [9]	59I	See Note [9]	See Note [9]	See Note [9]	2.3.8
Synchronization	Synchrocheck/synchronizing	25	Required	as per Section	as per Section	2.4.4

[1] All protection element functions must be shown on Single Line Diagrams, including those that are integrated into inverter controls. Net operation times of all protections must satisfy time constraints as specified in individual reference sections, additional time delay to be used as required.
[2] This column applies to DG facility greater than 500kW that consists of multiple inverter units. Projects up to 500 kW incorporating single or multiple inverters (single phase or three phase) that are certified in accordance with relevant CSA standards shall be deemed compliant to Table 10
[3] Protection functions not required because of inverter's active anti-islanding controls
[4] Directional Reactive Power relay is an alternative to 78 (Vector Surge) provided there is a predictable reverse reactive power flow for island conditions
[5] An alternative or complement to Over-current (50, 50N). Special caution is needed for selection of inverse-time characteristics that meets time constraints.
[6] May be used to provide distinction between normal load and feeder-end fault conditions when basic over-current (50, 50N) is insufficient
[7] May be used to provide distinction between internal and external faults for reconnection of DG
[8] Required for DG installations that do not in-feed ground current to ground faults on the distribution system
[9] May be required if DGIT connection is vulnerable to ferro-resonance e.g. open phase and HV delta connections

4.0 In the alternative Option 1 of the winding configuration of the interface transformer i.e, the Y:Y connected transformer, a tertiary Delta winding is required if the generator is grounded neutral. In the case of a generator with a low impedance grounding, would you still need a tertiary winding transformer?

If a transformer is connected, grounded Y:Y and the generator's neutral is ungrounded, a TOV issue will arise because no ground current is going to flow. Even when the generator neutral is grounded through low or any impedance, there is minimal ground current flow (on HV side for feeder ground faults), so the TOV issue is still there. With a delta tertiary, there is a path for zero sequence current to flow and consequently, TOV will no longer be an issue. However, subject to the CIA results, Y:Y (without tertiary) transformer connection is acceptable for projects up to 1 MVA on distribution feeders where single phase tripping is practiced.

5.0 Is there any preference when choosing the transformer for smaller installations?

Yes, there is a preference for smaller installations less than 1 MVA. It is recommend using Y:Y connected single-phase transformers (unless the CIA dictates otherwise) to ensure that there are no back feed issues (there is no three-phase isolating device on the high side). With three-phase common core transformers, a single line-to-ground fault may back feed through the actual core of the transformer and it can cause safety issues.

6.0 Will transfer trip from the TS be considered as the Ontario Grid Control Centre's ability to remotely disconnect a DG customer?

No. The transfer trip protection is keyed from relay operation verses a manual initiated trip from Supervisory Control. The manual trip would be initiated for a number of potential reasons such as the inability to establish communication combined with an urgent need to remove the generator from the system due to a connectivity change or loss of Transfer Trip Protection.

7.0 Who is responsible for performing "feeder studies", as well as paying for them?

The distribution feeder that the DG is connected to may change from time to time as loads, DGs and feeder sections are added or removed. Hydro One will be responsible for the protection assets owned by Hydro One, while the DG owner is responsible for protection assets at the DG facility. The term "responsible" implies the acceptance of maintenance costs incurred by each owner to support their assets.

8.0 What will be the procedure to reconnect after lockout? Can it be done from remote operation?

For the time being, there will be a need for the DG Owner and Hydro One operators to contact each other for permission to reconnect. The contact information will be provided to the DG Owner in the DCA. In the future, Hydro One recognizes the generators may wish us to provide a solution where a control signal may be sent to the DG Facility to allow reconnection, thus reducing the oral communication and generator staffing requirements.

9.0 Will loss of power at PCC be considered as voltage and frequency outside the operating range and trigger a 15 minute count down to lock out?

Loss of power at the PCC is considered an outage. The 15 minute countdown shall start once voltage and frequency are outside of the operating range (if there is no voltage, it is outside of operating range). If the voltage and frequency are not restored to within "normal operating ranges" (refer to Section 3.1.5 and 3.1.7 for normal voltage and frequency operating ranges) within 15 minutes, the automatic reconnection shall be locked out.

The "5 minute" countdown to reconnect the generator is triggered once voltage and frequency are restored to normal operating parameters as long as the automatic reconnection has not locked out (via the 15 minute counter mentioned above).

10.0 Why is the LV BF protection requirement to trip the HVI (and initiate BF on the HVI)? Initiating BF protection in the HVI from the LV BF protection is rarely, if ever done.

This requirement is based on zone tight protections at the DG. If independent backup protection devices are deployed that will detect and trip the HVI for faults between the LV breaker and the wind turbine generator, then there is no requirement for LV breaker failure protection (from HONI's perspective). For example, LVI is used as a primary means of disconnecting the DG Facility from the distribution system. DG facility is also equipped with HVI but the protections controlling the HVI are not capable of sensing faults on the LV side. Now, LVI breaker fail condition is required to trip the HVI and initiate the HVI breaker fail protection for the case where the HVI fails to open.

11.0 Will HONI be sending a continuous trip signal if outage is longer than 15 minutes?

No, although a continuous transfer trip signal may be sent if the DG does not respond with a DGEO signal. The DG Facility, if disconnected for whatever reason (protection operation or Transfer Trip receive) must monitor the voltage and frequency on all three distribution phases and if any is not within normal operating parameters within 15 minutes of disconnection, the DG Facility must NOT auto-reconnect to Hydro One's distribution system until Hydro One operators give permission.

12.0 How does one make a suggestion for consideration to review DG and interconnection standards, i.e. to reconsider the need to prioritize grid access for public benefit community power?

This question and any comments regarding the above subject matter should be referred to the OPA.

13.0 With the new amendments, how many DGIT options remain for connecting to a 44kV, 3-wire feeder with a nameplate capacity of 3MW (technology: solar)? Which DGIT option would apply best?

Only one option is now acceptable for connecting to a 44kV 3-wire feeder, regardless of DG technology type (rotating or inverter-based). The DG connection must be ungrounded, in other words, not contribute any zero sequence ground current from the DG facility to ground faults on the Distribution System. This can be accomplished with a Delta:Wye DGIT connection as shown in Figure 9 of the TIR document.

14.0 Is there a possibility of Hydro One supplying a simplified TIR document for smaller projects, i.e. less than 250 KW under the FIT program?

Hydro One now has two TIR documents.

- DT-10-015 covers Single-phase installations with an aggregate capacity > 10 kW; and Three-phase installations with an aggregate capacity > 30 kW
- DT-10-020 covers Micro Generation & Small Generation, 3-phase, less than 30 kW

There are no plans in the foreseeable future to create any more Hydro One TIR documents.

15.0 For inverter fed distributed generators as per the CSA/IEEE specified protection elements, there are protections in the generator that are related to the interconnect. Is this acceptable?

As per the revised Table10 of the TIR, some inter-connection protections for inverter-fed generators are required. These are listed under the column labeled as "Inverter". These protections are dedicated and stand alone protections that detect distribution system faults or islanding conditions and consequently, disconnect the generator from the grid. They can not be a part of the inverter controller or the generator protections if the DG capacity is above 500 kW. But as explained in

notes 2 and 3, for inverter-fed generator with capacity less than 500 kW, some of the protection can be implemented in the active controller of the inverter (these generators must be compliant with the relevant CSA standard). These protection functions include the anti-islanding protection, unbalance protection and phase/ground fault over-current protection.

As a general rule, implementation of such protections (in both cases, either below or above 500 kW) on the generator side is not acceptable as there may be situations that the protections on the generator can not properly detect the fault conditions on the feeder side. In addition to that, Hydro One review of the generator protections and settings is limited to the protections that impact the Hydro One feeder and Hydro One will not usually consider reviewing the protective functions at the generator (low voltage) side of the DG connection.

16.0 If the inverters are deemed compliant in Table 10, do we need to list these on the SLD?

Yes, even if deemed compliant, all inverters must be listed and seen on the SLD.

17.0 Please clarify grounding reactance/resistance requirements. Where are they specified in the TIR, referring to the point of connection to the grid?

The requirements for grounding (resistance and reactance) are covered in Section 2.1.11 items ix) and x).

18.0 Why the new option 7 SLD does not have an HVI?

Option 7 does have an HVI. It is used to switch the grounding transformer out-of service when the generator is not connected. This allows the load to remain connected at all times.

19.0 Regarding intensity of short-circuit faults, is it specified anywhere in the TIR document? Is it required for solar DG's?

Please refer to section 2.1.16 of the TIR. There are the maximum fault levels listed as set by the Transmission System Code (TSC). This is applicable to all DGs (including solar).

20.0 Does the TIR document provide information which can be used with respect to step up transformers so proponents have a better idea in designing and building the right transformer?

The Hydro One System Characteristics are presented in Appendix A. Specific requirements of DGIT with respect to winding configuration and grounding requirements are presented in Sections 2.1.11 and 2.1.12

21.0 Are there any recommendations for step up intermediate transformer windings?

Intermediate transformers are internal to the DG facility. Hydro One does not offer any recommendations regarding these transformers.

22.0 Among the interconnection transformer configuration diagrams, only Option #5, Fig. 6, shows multiple DGIT connections. Can other options also apply to multiple DGITs?

Yes, the other options listed can also apply to multiple DGITs.

23.0 For inverter type solar generators, how can solidly grounded and grounded through an impedance be defined? Does Fig. 7, option 6 apply to collector type application with multiple inverters and DGITs while the neutral of inverters is solidly grounded?

The requirements for grounding (resistance and reactance) are covered in Section 2.1.11 items ix) and x).

Fig. 7, option 6 can apply to a collector type application with multiple inverters and DGITs providing it complies with the grounding requirements as outlined above.

24.0 For a small 500kW solar farm, when the HVI is a fuse and the interconnection protection consists of fusing protection, unbalance protection with a SEL relay and 27/59/81 protection integrated in the inverter – are the above protection functions compliant with Table 10? For fusing protection, how would the protection be monitored or recorded?

The protections must comply with the individual sections in the TIR. The above description does not provide enough information to determine all of the protection requirements. A SLD and protection description with relay setting is required to be submitted to HONI for review to ensure all requirements are being met.

25.0 For DG facilities ≤500kW where Breaker Failure is not required, can a manual load break switch be used instead of motorized disconnect switch?

As per Section 2.1.7 of the TIR, all three phase DG Facility's isolation device shall be motorized if the DG Facility is larger than:
1) 250 kW when connecting to feeders operating below 15kV; and
2) 500 kW when connecting to feeders operating above 15kV