DT-10-015 R3

DISTRIBUTED GENERATION TECHNICAL INTERCONNECTION REQUIREMENTS

INTERCONNECTIONS AT VOLTAGES 50KV AND BELOW

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Hydro One Networks Inc.'s ("Hydro One" or "HONI") "Distributed Generation Technical Interconnection Requirements: Interconnections at Voltages 50kV and Below", including any updates of technical interconnection requirements in the form of bulletins and/or amendments that are published periodically by Hydro One on its website *(the "TIR"), identifies minimum requirements for generation projects connecting to Hydro One's distribution system or the distribution system of Embedded LDCs. Additional requirements may need to be met by the owner of the generation project to ensure that the final connection design meets all local and national standards and codes and is safe for the application intended. The requirements outlined in TIR are based on a number of assumptions, only some of which have been identified. Changing system conditions, standards and equipment may make those assumptions invalid. Use of the TIR and the information it contains is at the user's sole risk. Hydro One, nor any person employed on its behalf, makes no warranties or representations of any kind with respect to the TIR, including, without limitation, its quality, accuracy, completeness or fitness for any particular purpose, and Hydro One will not be liable for any loss or damage arising from the use of the TIR, any conclusions a user derives from the information in the TIR or any reliance by the user on the information it contains. Hydro One reserves the right to amend any of the requirements at any time. Any person wishing to make a decision based on the content of the TIR should consult with Hydro One prior to making any such decision.*

CONTACT/PUBLISHER

Please forward questions/comments regarding the TIR to the following email address:

EMAIL: DGConnectionReq@HydroOne.com

REVISION HISTORY

DATE	VERSION	COMMENTS
March 2013	Rev. 3	Added some definitions; updated the requirements for *Customer Owned New Line* and corrected the ratings for *Surge Arrester* in Section 2.1; some modifications to *Breaker Failure*, *Three Phase Generators* and *Anti-Islanding Protection* in Section 2.3; clarified the calculations in Appendix C; removed the COVER template in Appendix H.
June 2011	Rev. 2	Updated several sections as per the *Distributed Generation Technical Interconnected Requirements (TIR) Amendments Webinars, Part 1 and 2* – which can be seen via: http://www.hydroone.com/Generators/Pages/Webinars.aspx

DATE	VERSION	COMMENTS
February 2010	Rev. 1	Updated voltage & power factor requirements; minor adjustments in all diagrams; replaced “tap line” requirement with “new line” requirement; added missing definitions; minor modifications to “Capacity Limitations”; clarified PCC and Point of Connection.
November 2009	Rev. 0	New Report

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1 INTRODUCTION

The "Distributed Generation Technical Interconnection Requirements: Interconnections at Voltages 50kV and Below" (the "TIR") outlines the technical requirements for the installation or modification of Distributed Generation (DG) Facilities connecting to Hydro One Networks Inc.'s ("Hydro One") Distribution System feeders at ≤ 50kV.

Certain requirements including, but not limited to, transfer trip and control and monitoring may also apply to DG Facilities connecting to the Distribution System of an Embedded LDC other than Hydro One.

Connection of DG Facilities to Hydro One's Distribution System feeders impacts the steady-state and transient voltage profiles and current distribution along the feeder in response to changing supply, load and fault conditions. These impacts must be controlled to:

- ensure that the safety, reliability and efficiency of Hydro One's Distribution System is not materially adversely affected by the connection of DG Facilities to Hydro One's Distribution System or the Distribution System of an Embedded LDC;
- abide by the requirements of the Distribution System Code ("DSC") issued by the Ontario Energy Board, Ontario Electrical Safety Code ("OESC") and applicable CSA and IEEE standards; and
- be compatible with Hydro One's standard operating, protection, control and metering systems and practices.

To accomplish this, the design of the power equipment, protection, control and metering systems used at or for the connection of the DG Facility must meet specific minimum requirements. Depending on the capacity and electrical characteristics of the connecting DG Facility, specific additions and/or modifications may be required to Hydro One's power equipment, protection, control and metering systems to facilitate the connection.

The TIR has been developed with reference to the Canadian Standards Association such as CAN/CSA C22.3 No. 9-08 – Interconnection of Distributed Resources and Electricity Supply Systems, the DSC and international standards such as the Institute of Electrical and Electronics Engineers (IEEE) Standard 1547 – Interconnecting Distributed Resources with Electric Power Systems.

It is imperative that these requirements are understood as required by those delegated or contracted by the owner of a DG Facility ("DG Owner"), Hydro One and other affected Local

Distribution Company (LDC) owners for the planning, design, equipment manufacture and supply, construction, commissioning, operation and maintenance of the DG Facility and Distribution Systems.

1.1 SCOPE

The TIR applies to the following DG Facilities connecting to Hydro One's Distribution System (50kV and below):

1. Single-phase installations with an aggregate capacity > 10 kW; and
2. Three-phase installations with an aggregate capacity > 30 kW

The document is intended to be applied to electric power generators using all types of energy sources, energy storage and energy conversion technologies – directly connected synchronous and asynchronous rotating machines, and those connecting via inverters or static power converters which are above the thresholds mentioned above. The TIR does not apply to DG Facilities parallel with Hydro One's Distribution System for less than 100ms (Momentary Closed Transition Switching) except as noted in Section 2.1.23.

Section 2 contains minimum requirements that the DG Owner is required to comply with in order to connect its Generation Facility to Hydro One's Distribution System. Depending on the size of the DG Facility, the voltage of the interconnected distribution feeder, and whether the DG Facility is single-phase or three-phase (3-wire or 4-wire) certain requirements may not apply.

It is the DG Owner's responsibility to ensure that all TIR requirements are met. These TIR requirements have been developed by Hydro One to ensure that the integrity and power quality of Hydro One's Distribution System are maintained to acceptable levels after the connection of the DG Facility. The DG Owner may also have to meet additional or modified requirements to address unique situations and the DG Owner shall be advised of any such requirements at the appropriate stage by Hydro One. Any exemptions to the TIR require Hydro One's prior written approval.

The TIR does not specify protection requirements for the protection of the generator and other equipment at the DG Facility. The DG Owner is responsible for installing, owning and operating adequate generator protections as well as protections for other equipment within the DG Facility to protect them from damage from faults or abnormal conditions which may originate at the DG Facility or from Hydro One's Transmission System and/or Distribution System.

The TIR does not constitute a design handbook and is not a substitute for the Ontario Electrical Safety Code. DG Owners who are considering the development of a DG Facility to connect to Hydro One's system[1] shall engage the services of a professional engineer or a registered consulting firm qualified to provide design and consulting services for electrical interconnection facilities in the Province of Ontario.

1.2 OBJECTIVES

Hydro One is committed to connecting DG Facilities to the Distribution System while preserving a safe and reliable electrical supply to all of its customers. The connection of the DG Facilities must conform to relevant Ontario and Canadian regulations and international design standards. The TIR has been developed in accordance with the following objectives. These objectives shall be integrated into all steps to the connection process - design specification, construction, operation and maintenance of the DG Facility.

SAFETY

The connection of a DG Facility must not create a safety hazard for the general public, other Hydro One customers, Hydro One employees or others that work on the Distribution System, nor to personnel working in the DG Facility.

POWER QUALITY

The connection of a DG Facility must not materially degrade the power quality of Hydro One's Distribution System below acceptable levels.

RELIABILITY

The connection of a DG Facility must not materially compromise the reliability of Hydro One's Distribution System as required by the DSC and defined by Hydro One's Conditions of Service document.

ACHIEVABILITY

The connection requirements for DG Facilities must be achievable, fair and competitive to allow equitable access for all DG Owners.

OPERABILITY

[1] The TIR also applies to DG Facilities connecting to Hybrid Feeders (feeders owned partially by Hydro One)

The connection of a DG Facility must not restrict the operation of Hydro One's Distribution System. All aspects of the connection that can impact Hydro One's Distribution System must be compatible with Hydro One's standard operating, protection, control and metering systems and practices.

1.3 RESPONSIBILITIES

Connecting DG Facilities to Hydro One's Distribution System involves several steps and both Hydro One and the DG Owner have distinct responsibilities.

Hydro One is responsible for:

- the safety, reliability, power quality and operation of Hydro One's Distribution System, and ensuring the connection of the DG Facility does not adversely affect the system or Hydro One's existing customers;
- maintaining the integrity of Hydro One's Transmission and Distribution Systems;
- operating in compliance with all applicable laws (including its license and codes issued by the Ontario Energy Board) and within the guidelines of all applicable Ontario, Canadian and international standards; and
- establishing the terms and conditions for the TIR that are consistent with the "Objectives" described above in Section 1.2.

DG Owners are responsible for:

- the safety, design, construction, operation, metering, protection and control, and maintenance of the DG Facility;
- operating in compliance with all applicable laws (including its license and codes issued by the Ontario Energy Board) and within the guidelines of all applicable Ontario, Canadian and international standards;
- ensuring that the DG Facility is compatible with Hydro One's standard operating, protection, control and metering systems and practices; and
- abiding by the terms and conditions of the TIR.

1.4 REQUIREMENT ORIGINS

Table 1 below shows the origins of the requirements found within the TIR.

Table 1: Origins of Requirements

Hydro One Networks Inc. Requirements are classified as:	If:
Verbatim	They are a direct application (no change) of stated standards
Selective	HONI has chosen the most applicable requirements from standards having varying requirements
Optimal	HONI has found an optimal solution for its Distribution System to meet the stated standards
Unique	Requirements are unique to meet HONI's Business Practice objectives

			Regulation and Standards				
#	TIR Section	HONI	OESC	IEEE (1547)	IEC 60834	C22.3 No. 9-08	DSC
2.1	General Requirements						
2.1.1	Safety	Verbatim	2-200	1.2		1.4	4.6 Appx. F.1 & F.2
2.1.2	Active Power	Optimal		4.1.1		5	Appx. F.1; F.2 - 3.1, 5.1
2.1.3	Reactive Power	Optimal		4.1.1		5, 7.2.4	Appx. F.1; F.2 – 3.1, 5.1
2.1.4	Equipment Rating and Requirements	Verbatim	2-004, 2-010(d), 2-024	4.1.1		5, 7.4.2	6.2.14, 6.2.29, Appx. F.1 & F.2 – 3.1, 5
2.1.5	Point of Common Coupling	Optimal	84-026	1.2, 3.1.3		1.1,3, Figure 1	Appx. F.2 – 1
2.1.6	Customer Owned New Line	Optimal	Bulletin 36-17-4	4.1.7		1.1, 7.3.1	Appx. F.2 – 1
2.1.7	Isolation Device	Selective	84-024, 84-026	4.1.7		7.3.1	4.5.2, Appx. F.2 – 1, 1
2.1.8	Interrupting Device Rating	Selective	2-004, 2-024			7.4.2	Appx. F.2 – 5
2.1.9	Phasing	Verbatim				6.10, 7.3.4	
2.1.10	Temporary Over-Voltage (TOV)	Selective		4.1.2		7.3.3, 7.4.7.1	Appx. F.2 – 2

			Regulation and Standards				
#	TIR Section	HONI	OESC	IEEE (1547)	IEC 60834	C22.3 No. 9-08	DSC
2.1.11	Grounding	**Selective**	10, 84-28	4.1.2		7.3.3	Appx. F.2 – 2
2.1.12	Interconnection Transformer Configuration	**Optimal**		4.1.2		7.3.2, 7.3.3, 7.4.9	Appx. F.2 – 2
2.1.13	High Voltage Interrupting Device (HVI)	**Optimal**				7.3.5	Appx. F.2 – 2
2.1.14	Station Service for Essential Loads	**Optimal**				7.4.19	4.1.6
2.1.15	Batteries/DC Supply	**Optimal**	46-104			7.4.19	4.1.6
2.1.16	Fault Levels	**Optimal**	2-004, 2-024			6.8, 7.4.2	Appx. F.2 – 5
2.1.17	Insulation Coordination	**Optimal**	26-500			7.4.18	
2.1.18	Instrument Transformers for Use in Protection Systems	**Optimal**		C57.13		7.4.2.1	
2.1.19	Power Quality Monitoring Device	**Optimal**		4.3		7.2	4.1.1, 4.1.3, Appx. F.2 – 10
2.1.20	Protection from Electromagnetic Interference (EMI)	**Verbatim**		4.1.8.1		7.4.17	Appx. F.2 – 10.4
2.1.21	Surge Withstand	**Verbatim**	84-014	4.1.8.2		7.4.18	Appx. F.2 – 10.5
2.1.22	DG Facility Acceptance	**Optimal**					6.2.18, Appx. F.1
2.1.23	Generators Paralleling for 6 Cycles or Less (Closed Transition Switching)	**Selective**		1.3, 4.1.4		7.4.13	
2.1.24	Provision for Future Changes	**Optimal**					2.4.8, 6.2.29
2.2	Performance Requirements						
2.2.1	General	**Optimal**					3.1.1, 4.1.1, 4.1.4, 4.2.6, 4.4.1, Appx. F1
2.2.2	Power Quality						
2.2.2.1	Voltage	**Verbatim**		4.1.1, 4.2.3		6.2	4.1.2, 6.2.14, Appx. F.2 - 3.1
2.2.2.2	Voltage and Current Unbalance	**Selective**				7.2.5	Appx. F.2 – 3.2

		Regulation and Standards					
#	TIR Section	HONI	OESC	IEEE (1547)	IEC 60834	C22.3 No. 9-08	DSC (Appendix F)
2.2.2.3	Voltage Fluctuations (Flicker)	**Verbatim**		4.1.3, 4.3.2, 5.1.2		6.4, 7.2.2, 7.4.14	Appx. F.2 – 3.2, 10.1
2.2.2.4	Voltage and Current Harmonics	**Verbatim**		4.3.3, 5.1.6, Tables 3 & 6		6.4, 7.2.1, Table 1, B2	Appx. F.2 – 10.2
2.2.2.5	Frequency	**Verbatim**		4.2.4, Table 2		7.2.3, 7.4.15, Table 3	Appx. F.2 – 6.5
2.2.2.6	Power Factor	**Selective**				7.2.4	Appx. F.2 – 4
2.2.2.7	Limitation of DC Injection	**Verbatim**		4.3.1		7.2.7	Appx. F.2 – 10.3
2.2.3	Disturbances	**Verbatim**				7.3.3	Appx. F.2 – 2
2.2.4	Resonance Analysis	**Optimal**				7.2.6	
2.2.5	Self-Excitation Analysis	**Optimal**				7.2.6	
2.3	Protection Requirements						
2.3.1	General Requirements	**Optimal**		4.1.2, 4.2, 4.4		4, 6.8, 6.11, 6.13, 7.4	2.4.6, 3.1.2, 3.2.11, 4.1.1, 4.4.3, 6.2.11, 6.2.14, 6.2.18, Appx. F.1
2.3.2	Sensitivity and Coordination	**Optimal**				7.3.3, 7.4.1.3	Appx. F.2 – 2, 6.4
2.3.3	Protection Operating Times	**Optimal**		4.2		7.4	
2.3.4	Breaker Fail (BF)	**Optimal**				7.4.20.1	4.1.6, Appx. F.2 - 6.4
2.3.5	Single Phase Generators	**Optimal**		4.2.3, IEEE Std 929		7.4	Appx. F.2 – 6.4
2.3.6	Three Phase Generators	**Optimal**	64-112, 84-008, 84-018	4.2		7.4	Appx. F.2 – 6.4
2.3.7	Phase and Ground Fault Protection	**Selective**		4.2.1		7.4.4	Appx. F.2 – 6.4
2.3.8	Open Phase Protection	**Optimal**				7.4.5	
2.3.9	Feeder Relay Directioning	**Verbatim**					Appx. F.2 – 8
2.3.10	Over Frequency/Under Frequency Protection	**Verbatim**		4.2.4, Table 2		7.2.3, 7.4.6, 7.4.15, Table 3	Appx. F.2 – 6.5
2.3.11	Overvoltage/Undervoltage Protection	**Verbatim**		4.2.3, Table 1		7.4.7, Table 4	Appx. F.2 – 6.5

2.3.12	Anti-Islanding Protection	Optimal		4.4.1		7.4.8	Appx. F.2 – 6.1.2
				Regulation and Standards			
#	TIR Section	HONI	OESC	IEEE (1547)	IEC 60834	C22.3 No. 9-08	DSC (Appendix F)
2.3.13	Transfer Trip	Optimal		4.4.1		7.4.8, 7.4.12	Appx. F.2 – 6.1.2
2.3.14	Distributed Generator End Open (DGEO)	Optimal		4.2.2		6.11	Appx. F.2 – 6
2.3.15	Low Set Block Signal (LSBS)	Optimal		4.2.2		6.11	Appx. F.2 – 6
2.3.16	DGEO and LSBS Design	Optimal		4.2.2		6.11	Appx. F.2 – 6
2.3.17	Special Interconnection Protection	Optimal					2.4.8, 6.2.29
2.3.18	Protection Scheme Failures	Optimal		4.2.2		7.4.20	4.1.6, Appx. F.2 – 6.4
2.3.19	Interconnection Protection Acceptance	Optimal				4, 6.8	2.4.6, 3.1.2, 3.2.11, 4.1.1, 4.4.3, 6.2.11, 6.2.11, 6.2.14, 6.2.18, Appx. F.1
2.3.20	Protection Changes	Optimal				8.6	
2.4	Operating Requirements						
2.4.1	General	Optimal					3.1.1, 4.1.1, 4.1.4, 4.2.6, 4.4.1, Appx. F.1
2.4.2	Islanding	Verbatim		4.4.1		7.4.8	Appx. F.2 – 6.1.2
2.4.3	Unintentional Energization	Verbatim		4.1.5		7.4.10	Appx. F.2 – 6
2.4.4	Synchronization	Verbatim		4.1.3, 1547.2 (8.1.3, 9.2.3)		7.4.14, Table 6	Appx. F.1 – 3.2
2.4.5	Single Connection Path	Optimal				6.12	
2.4.6	Automatic Disconnection of Generation and HV Ground Sources	Optimal		4.1.2		7.3.3	Appx. F.2 – 2, 6.4
2.4.7	Automatic Reconnection of Generation and HV Ground Sources	Optimal		4.2.6		7.4.11	Appx. F.2 – 2, 6.4
2.4.8	Reconnection of DG Facility Generation Following a Sustained Outage or Shutdown	Optimal		4.2.6		7.4.11	Appx. F.2 – 2, 6.4

				Regulation and Standards			
#	TIR Section	HONI	OESC	IEEE (1547)	IEC 60834	C22.3 No. 9-08	DSC (Appendix F)
2.5	Control and Monitoring Requirements						
2.5.1	General	**Selective**		1547.3 (Section 4)			Appx. F.2 – 9, TSC App 1, sch E, Section 1.6
2.5.2	Control Facilities	**Selective**					TSC Schedule G
2.5.3	Operating Data, Telemetry and Monitoring	**Selective**		1547.3 (Section 5)			
2.6	Telecommunications Requirements						
2.6.1	General	**Unique**					
2.6.2	Telecommunications Facilities for Teleprotection	**Unique**					
2.6.3	Telecommunications Facilities for Real-Time Control and Monitoring	**Selective**		1547.3 (Section 4)			
2.6.4	Reliability Requirements	**Selective**		1547.3 (Section 4)	IEC 60834-1		
2.7	Reporting Requirements						
2.7.1	General Reporting Requirements	**Selective**					4.1.3
2.7.2	Power Quality Recording	**Optimal**		1547.3			
2.7.3	Disturbance Fault Recording	**Optimal**		1547.3			
2.7.4	Sequence of Events Recording	**Optimal**		1547.3			
2.8	Metering Requirements	**Optimal**	6-400 – 6-412				5.2, Appx. F.1, F.2 – 7

			Regulation and Standards				
#	TIR Section	HONI	OESC	IEEE (1547)	IEC 60834	C22.3 No. 9-08	DSC (Appendix F)
2.9	Commissioning and Verification Requirements	**Optimal**	Appx. B 14-102	5.4		8.4	6.2.19, Appx. F.1
2.10	Maintenance Requirements	**Optimal**	2-006, 2-010, 2-300			8.5	4.4, 6.2.15, 6.2.27, 6.4.3, Appx. F.2
2.11	Connection Process Requirement	**Optimal**					Appx. F.1

1.5 TERMINOLOGY

Throughout the TIR, the term:

- “shall” is used to express a mandatory requirement – i.e. a provision that the DG Facility is obligated to satisfy in order to comply with the requirements of the TIR;
- “should” is used to express a recommendation or that which is advised but not required;
- “may” is used to express an option or that which is permissible within the limits of the TIR; and
- “can” is used to express possibility or capability.

Individual TIR requirement may be followed by a “Background Information” and “Design Considerations” section which do not include requirements or alternative requirements. The purpose of these sections is to provide informative material, rationale on which the requirements in the section are based on and some design considerations. These sections are included where Hydro One considered them necessary or helpful and are not necessarily present for all TIR requirements. Hydro One does not take any responsibility for this information and the engineering consultant designing the DG Facility can decide whether to take the information into consideration when designing the project.

Appendices are designated as normative if they are mandatory requirements or informative if they are not mandatory requirements to define their application.

1.6 CAPACITY LIMITATIONS ON GENERATOR INTERCONNECTIONS FEEDER LOADING LIMITS

The capacity for all sections of all feeders, the “feeder limitation,” is based mainly on the distance from Hydro One supply station to the Point of Common Coupling (PCC) of the DG Facility. The feeder limitation applies to all DG Facilities connected or connecting to the feeder and considers the rated output capacity of each DG Facility. Any single DG Facility connection can affect the capacity available for all sections of the feeder.

For all sections of the feeder, the total current shall not exceed:

a) 400 Amps for Hydro One feeders operating at voltages 13kV or greater; and

b) 200 Amps for Hydro One feeders operating at voltages below 13kV.

ACCEPTABLE GENERATION LIMIT AT A TS OR A DS

The acceptable generation limit at a Hydro One TS or a Hydro One DS is established by adding together: 60% of maximum MVA rating of the single transformer and the minimum station load.

SHORT CIRCUIT (SC) LIMITS

The SC limits at TS low voltage bus or at any portion of distribution feeder shall not be exceeded by the addition of DG Facilities. Refer to Section 2.1.16 for the requirement.

1.6.1 THREE PHASE GENERATORS

i) The acceptable individual generation limits for three-phase DG Facilities connecting to Hydro One's Distribution System feeders shall not exceed:

a) 1 MW per connection on feeders operating at voltages below 13kV; and

b) 5 MW per connection on 27.6kV feeders supplied via a 44kV:27.6kV step-down transformer.

ii) The feeder limitation determines the total acceptable three-phase generation allowed for all sections of Hydro One's Distribution System feeders and shall not exceed:

a) 30 MW for feeders operating at 44kV;

b) 19 MW for feeders operating at 27.6kV;

c) 9.6 MW for feeders operating at 13.8kV;

d) 4.3 MW for feeders operating at 12.48kV;

e) 2.9 MW for feeders operating at 8.32kV; and

f) 1.45 MW for feeders operating at 4.16kV.

1.6.2 SINGLE PHASE GENERATORS

i) The acceptable individual generation limits for single-phase DG Facilities connecting to Hydro One's Distribution System shall not exceed:

a) 150 kW per connection on feeders operating at nominal voltage levels of 13kV or greater; and

b) 100 kW per connection on feeders operating at nominal voltage levels less than 13kV.

Note: While the absolute limits are stated above, the actual acceptable individual single phase generation limit for specific feeders or TS/DS is determined in Connection Impact Assessment (CIA).

1.7 DOCUMENT REPRODUCTION

The TIR may be reproduced or copied in whole or in part provided that credit is given to Hydro One and is not sold for profit.

1.8 TERMS AND DEFINITIONS

The Term	means…
ANSI	American National Standards Institute
Anti-Islanding	A protection system aimed at detecting islanded conditions (see island) and disconnecting the DG Facility from the Distribution System if an island forms
AVR	Automatic Voltage Regulator
BF	Breaker Fail
Breaker	Fault Interrupting Device: this may be a breaker, circuit switcher, HVI, LVI
CCE	Connection Cost Estimate
CCA	Connection Cost Agreement
CEA	The Canadian Electricity Association
CIA	Connection Impact Assessment
Class 1	DG Facility aggregate capacity at PCC ≤ 250kW
Class 2	250kW < DG Facility aggregate capacity at PCC < 1500kW
Class 3	1.5MW ≤ DG Facility aggregate capacity at PCC ≤ 10MW
Class 4	DG Facility aggregate capacity at PCC > 10MW
Clearing Time	See Trip Time

CO	Central Office: a local telephone company office that provides a central point for the termination of telecommunication lines and trunks, and where they can be interconnected.
COG	Coefficient of grounding - is defined as 100% x E_{LG}/E_{LL} where: • E_{LG} is the highest rms, line-to-ground, power-frequency voltage, on a sound phase, at a selected location, during a line-to-ground fault affecting one or more phases. • E_{LL} is the line-to-line power-frequency voltage that would be obtained, at a selected location, with the power fault removed. COG for three-phase systems are calculated from the phase-sequence impedance components, as viewed from the fault location. The COG is useful in the selection of a surge arrester rating for a selected location
COMTRADE	Common Format for Transient Data Exchange
COVER	Confirmation of Verification Evidence Report
CSA	The Canadian Standards Association
DESN	Dual Element Spot Network – Type of TS
DCA	Distribution Connection Agreement
Demarcation Point	The point at which the Hydro One equipment ends and another party's equipment begins.
DFR	Disturbance Fault Recorder
DG	See Distributed Generation *Formerly referred to as EG – Embedded Generator
DGEO	Distributed Generator End Open: a signal used to confirm the status of the generator breaker – used to prevent out-of-phase reclosing onto the generator *Formerly referred to as EGEO – Embedded Generator End Open
DG Facility	All equipment including generators, transformers, protections, and line on the DG Facility side of the PCC
DGIT or DG Interconnection Transformer	The transformer used to step up the voltage from the DG to distribution voltage levels.
DG Owner	A person who owns or operates a generation facility.

Distributed Generation (DG)	A generation facility which is not directly connected to the IESO-controlled grid but instead is connected to a Distribution System.
Distributed Generation Technical Interconnection Requirements: Interconnections at Voltages 50kV and Below	This document as well as any updates of technical interconnection requirements in the form of bulletins and/or amendments that are published periodically by Hydro One on its website.
Distributed Generator (DG)	See Distributed Generation
Distribution Connection Agreement	The DG Owner is required to enter into a Distribution Connection Agreement with Hydro One prior to generating electricity into the system
Distribution Lines	Distribution System lines that operate at nominal line-line voltages below 27.6 kV.
Distribution System	Any power line facilities under the operating authority of the Wires owner (Hydro One or LDC) that operate at nominal line-line voltages of 50 kV or below. This includes sub-transmission power lines that operate at 27.6 kV or 44 kV and distribution lines that operate at voltages below 27.6 kV.
Distributor	The electric utility owning or operating the distribution lines.
DNP 3.0	Distributed Network Protocol
DO	Drop Out
DS	An electrical station that is used to step down a sub-transmission voltage to a distribution voltage for distribution to the end use customer.
DSC	Distribution System Code
Effectively Grounded	A system grounded through a sufficiently low impedance so that COG does not exceed 80%. This value is obtained approximately when, for all system conditions, the ratio of the zero-sequence reactance to the positive-sequence reactance ($\mathbf{X}_0/\mathbf{X}_1$) is positive and ≤ 3, and the ratio of zero-sequence resistance to positive-sequence reactance ($\mathbf{R}_0/\mathbf{X}_1$) is positive and < 1.

Embedded LDC	A distributor who is not a wholesale market participant and is provided electricity by a host distributor.
EMI	Electromagnetic Interference
ESA	Electrical Safety Authority
Essential Loads	Part of the load that requires continuous quality electric power for its successful operation or devices and equipment whose failure to operate satisfactorily jeopardizes the health or safety of personnel, and/or results in loss of function, financial loss, or damage to property deemed essential by the user
F Class Feeder	Distribution feeder emanating from a Hydro One DS or HVDS
Feeder	A single-phase or three-phase line emanating from a substation to supply load.
Ferroresonance	A phenomenon caused by the interaction of system capacitance and nonlinear inductance of a transformer, usually resulting in very high transient or sustained overvoltage.
Ferroresonance Protection (59I)	Ferroresonance detection can be accomplished with a peak detecting overvoltage element (59I). This type of element is able to respond to the sub cycle high peak voltages that are characteristic of the ferroresonance phenomena. Standard overvoltage elements typically employ RMS calculations to the waveform and may not be able to detect the high peaks as they will be averaged with low peak values that also may occur. Where ferroresonance is expected or found to be a problem, ferroresonance detection will be required by the interconnection protection at the DG Facility location to disconnect the DG Facility.
Generator	See DG Owner
GPR	Ground Potential Rise: IEEE defines this as the voltage that a station grounding grid may attain relative to a distant grounding point assumed to be at the potential of remote earth.
GPS	Global Positioning System
Harmonics	Sinusoidal voltages and currents at frequencies that are integral multiples of the fundamental power frequency (60Hz).
High Voltage	In TIR, high voltage refers to Hydro One's system voltage and can be referred to as medium voltage.

Hydro One or "HONI"	Hydro One Networks Inc.
HVDS	High Voltage Distribution Station: the distribution station connected directly to Hydro One's transmission system (115kV system) which steps down transmission voltage to distribution voltage for distribution to the end use customer.
HVGT	HV Grounding Transformer
HV Ground Source	Three-phase ground sources are any three-phase power transformers or grounding transformers that provide a ground-current (zero-sequence) return path to phase-ground faults on the HV side of the DGIT. That includes separate HV grounding transformers or DGITs that have star-connected HV winding with the star-point neutral connected to ground, either solidly or through a reactor.
HVI	High Voltage Interrupter – any breaker/fault clearing device that is on the Hydro One side of the DGIT – voltage rating is usually at medium voltage distribution level.
Hybrid Feeders	Feeders owned partly by Hydro One and partly by other entities (e.g. Hydro One owns the first 50% of the feeder, and an LDC owns the remainder of the feeder).
ICCP	Inter-Control Center Communications Protocol
IEEE	The Institute of Electrical and Electronics Engineers
IED	Intelligent Electronic Device
IESO	Independent Electricity System Operator
Interrupting Device	The device used to disconnect generation from Hydro One's Distribution System: this may be a high voltage interrupter (HVI) or through a low voltage interrupter/breaker (LVI).
Island	An operating condition where a DG Facility(ies) is (are) supplying load(s) that is electrically separated from the main electric utility.
Load	The amount of power supplied or required at a specific location.

Load Factor	Ratio of average load during a designated period to the peak (maximum) load in the same period.
Load Flow Study	Steady state computer simulation study of voltages and currents in the Distribution System.
LSBS	Low Set Block Signal – signal sent over the same channel as DGEO which blocks the Low Set Instantaneous Protections at Hydro One's stations - to prevent inadvertent trips due to transformer inrush during energization.
LVGT	Low Voltage Grounding Transformer
LVI	Low Voltage Interrupter
MCOV	Maximum Continuous Operating Voltage
Medium Voltage	See High Voltage
M Class Feeder	Distribution feeder emanating from a Hydro One TS
NDZ	Non Detection Zone – range where passive anti-islanding protection may not operate within required time due to the small mismatch between generation and load
NERC	North American Electric Reliability Corporation
NEV	Neutral to Earth Voltage
NPCC	NorthEast Power Coordinating Council
MTBF	Mean Time Between Failure
MTTR	Mean Time to Repair
OEB	Ontario Energy Board
OESC	Ontario Electrical Safety Code
OGCC	Ontario Grid Control Centre
Parallel Operation	The state and operation where the DG Facility is connected to the Distribution System and supplies loads along with the electric grid.
PCC or Point of Common Coupling	The point where the DG Facility is connected to Hydro One's Distribution System

Point of Connection	The point where the new DG Facility's connection assets or new line expansion assets will be connected to Hydro One's existing Distribution System
Pst	A measure of short-term perception of flicker obtained for a ten minute interval
PSS	Power System Stabilizer
Plt	A measure of long-term perception of flicker obtained for a two-hour period
PQ	Power Quality
Protection Scheme	Protection functions including associated sensors, relays, CTs, VTs, power supplies, intended to protect a Distribution System or interconnected facility.
PT	Potential Transformer
PU	Pick Up
Resonance	A tendency of a system to oscillate at maximum amplitude at certain frequencies, usually resulting in very high voltages and currents.
RLSS	Rotational Load Shedding Schedules
ROCOF	Rate-of-change-of-frequency
RMS	Root Mean Square
RTU	Remote terminal unit
SC	Short Circuit Current
SCADA	Supervisory Control and Data Acquisition
SER	Sequence of Events Recorder
Service Provider	A Service Provider is an entity that provides services to other entities.
SIA	System Impact Assessment

SLD	Single Line Diagram
SPS	Special Protection Scheme
Stabilized	A Distribution System returning to normal frequency and voltage after a disturbance for a period of 5 minutes or as determined by the Wires Owner.
Sub-transmission Lines	27.6kV or 44kV Hydro One owned distribution lines
Synchronized	See Parallel Operation
Telemeter	Transfer of metering data using communication systems
TCA	Transmission Connection Agreement
THD	Total Harmonic Distortion – a measurement of the harmonic distortion present. It is defined as a ratio of the sum of the powers of all harmonic components to the power of the fundamental frequency.
TIR	Abbreviation for “Distributed Generation Technical Interconnection Requirements: Interconnections at Voltages 50kV and Below”
TOV	Temporary Overvoltage – oscillatory power frequency overvoltages of relatively long duration – from a few cycles to hours.
Transmission System	Any power line facilities under the operating authority of the Wires Owner usually operating at voltages higher than 50kV, line to line.
Transfer Trip	A signal sent over communication channels from upstream devices commanding the DG Facility to disconnect from Hydro One's Distribution System.
Trip Time	The time between the start of the abnormal condition to the time where the system disconnects and ceases to energize the Distribution System.
TS	An electrical station that is used to step down transmission voltage to a sub-transmission voltage for distribution to the end use customer and Distribution Stations (“DS”).
TSC	Transmission System Code
TT	See Transfer Trip

Type Test	Test performed on a sample of a particular model or device to verify its operation and design.
ULTC	Under-Load Tap Changer
UTC	Coordinated Universal Time
VT	Voltage Transformer
Wires Owner	The entity who owns and/or operates a Distribution System or distribution lines.

2 TECHNICAL INTERCONNECTION REQUIREMENTS

2.1 GENERAL REQUIREMENTS

2.1.1 SAFETY

i) The connection, installation and operation of a DG Facility shall not create a safety hazard to Hydro One's personnel, customers, general public and personnel working in the DG Facility.

BACKGROUND INFORMATION

Safety is of primary concern and shall be the main consideration when designing the DG Facility. The primary concern of the TIR is to provide interconnection specifications to ensure that safety will be maintained.

2.1.2 ACTIVE POWER

i) The DG Facility shall have to restrict their active power export to the project capacity which was applied for and assessed in the Connection Impact Assessment.

[Note: Typically the generator's Name Plate Capacity or Gen-Set Name Plate Capacity shall be considered as project size.]

2.1.3 REACTIVE POWER

i) The DG Facility shall comply with voltage and power factor requirements in Section 2.2.2.1 and Section 2.2.2.6 respectively.

2.1.4 EQUIPMENT RATING AND REQUIREMENTS

i) All electrical equipment and its installation shall be approved as required by Rule 2-024 and Rule 2-004, respectively, of the Ontario Electric Safety Code.

ii) The DG Facility shall have a connection authorization from ESA prior to a Distribution Connection Agreement with Hydro One.

iii) The DG Facility shall be maintained throughout the life of the assets to ensure that the DG Facility operates as designed.

iv) The DG Facility interface equipment shall be compatible with Hydro One's Distribution System equipment at the connection voltage which includes but not limited to:

a) Maximum Voltage;

b) Basic Impulse Limit;

c) Short Circuit Ratings; and

d) Capacity.

v) Connection of DG Facilities shall not cause the ratings of Hydro One's Distribution and Transmission System equipment to be exceeded for all operating conditions. This includes, but is not limited to:

a) equipment thermal loading limits; and

b) equipment short circuit limits.

vi) Where reverse power flow is possible, all existing voltage regulating and metering devices shall be made suitable for bi-directional flow.

vii) Changes to Hydro One's Distribution and Transmission System equipment ratings due to the interconnection of DG Facilities shall be assessed by the Hydro One's CIA.

BACKGROUND INFORMATION

All existing Hydro One's equipment in the distribution or transmission system shall not be overloaded beyond acceptable limits. All interrupting devices shall be capable of interrupting the maximum fault current under all operating conditions of the DG Facility. It must be ensured that conductors, voltage regulators, regulating stations, reclosers, circuit breakers, transformers, etc. in Hydro One's Distribution and Transmission System are operating within their respected ratings.

All regulating devices and metering devices which are designed for unidirectional power flow may need to be upgraded or replaced to ensure they are capable of handling bi-directional power flow.

2.1.5 POINT OF COMMON COUPLING

i) The PCC must be identified on the single line diagram (SLD).

ii) The DG Owner shall be responsible for the design, construction, maintenance and operation of the facilities and equipment on the DG Facility side of the PCC.

iii) All equipment on the DG Facility side of the PCC shall be in accordance with Section 2.1.4.

iv) Hydro One shall be responsible for the design, construction, maintenance and operation of the facilities on the Hydro One's side of the PCC.

v) When specifications and parameters (such as voltage, frequency, and power quality) are mentioned throughout the TIR, they must be met at the PCC unless otherwise stated.

vi) Hydro One or the DG Owner may require that their equipment be located on the other side of the PCC. In this case, the DG owner must provide the necessary space for Hydro One to install such equipment and Hydro One is to approve this site.

vii) A 120V AC power service is to be available for Item (vi) above.

BACKGROUND INFORMATION

The Point of Connection means the point where the new DG Facility's connection assets or new line expansion assets will be connected to the existing Hydro One's Distribution System. The Point of Common Coupling (PCC) means the point where the DG Facility is to connect to Hydro One's Distribution System. The Point of Connection may be the same as the PCC, especially if the DG Facility lies along the existing Hydro One's Distribution System. The PCC may be located somewhere between the Point of Connection and the DG Facility if the new line will be owned by Hydro One. These definitions have been adopted by Hydro One to align with the DSC and not with CSA C22.3 No. 9-08 standard. Refer to Figure 1 for interconnection terminology. The PCC shall be identified on the single line diagram (SLD), as shown below in Figure 1.

In addition to the Items mentioned above, Hydro One will also carry out the engineering, design and construction required for additional changes to Hydro One's system in order to facilitate the connection of the DG Facility. The DG Owner may be responsible for some or all of the costs of such changes.

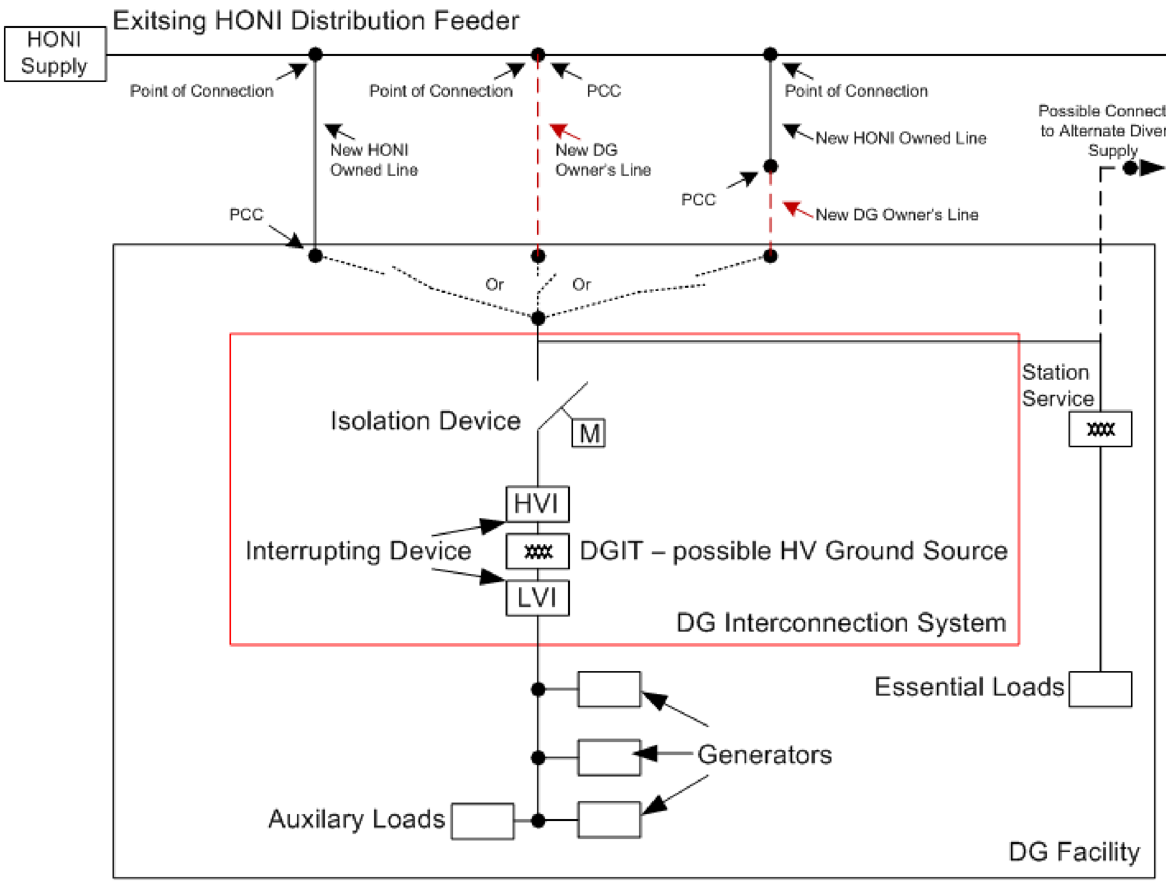


Figure 1: Simplified SLD – Interconnection Terminology

2.1.6 CUSTOMER OWNED NEW LINE

This section applies to DG Owner's new lines that connect to Hydro One's Distribution System at the PCC. It does not apply to those DG Facilities that are connecting to existing customer owned facilities.

i) A load break switch for a new line owned by the DG Owner is required at the PCC to manually disconnect the DG Owner's line from Hydro One's Distribution System:

a) The load break switch shall be gang-operated for multi-phase applications;

b) The switch shall have the same requirements as the isolation device in Section 2.1.7 except that it does not have to be motorized;

c) The load break switch must be capable of taking the line off potential safely based on, but not limited to, circuit capacitance, transformer connections and load considerations;

d) An overcurrent protection device as outlined in Item (ii) below can serve the purpose of the load break switch provided that it is located at the PCC and it can manually disconnect load simultaneously on all phases. If the overcurrent protection device cannot be visually verified to be open, an additional isolating device shall be provided for work protection purpose. This may be in the form of single phase solid blade switch, opener, etc.

ii) An overcurrent protection device is required to automatically disconnect the DG Owner's line from Hydro One's Distribution System for faults on the DG Owner's line or equipment, as outlined below:

a) For DG Facilities connecting to Hydro One's 3-wire systems, the overcurrent protection device should provide 3-phase gang-operated fault interruption. For those connecting to Hydro One's 4-wire systems, the overcurrent protection device can be single-phase or three-phase gang-operated;

b) The overcurrent protection device shall meet, but not be limited to, the following criteria:

1) The interrupting rating shall account for present and future anticipated fault levels;

2) The setting shall be coordinated with the timed elements of upstream protective devices, and it shall be sensitive enough to operate for minimum Hydro One infeed to faults on the customer owned new line;

3) If fuses are used, they should not operate for maximum DG infeed to faults on the interconnected feeder;

4) If a recloser is used, automatic reclosing shall be disabled.

c) The location of the overcurrent protection device must be as close to the PCC as practical. It can be either on the first or second pole after the PCC, depending on whether a dedicated pole is required to be used for the revenue metering. Under the following circumstances, the overcurrent protection device can be located at or near the DGIT, on the high voltage side:

1) For new line length not exceeding 200m;

2) For DG Facilities with more than one interconnection transformer where the total HV circuit length from the PCC does not exceed 200m;

3) For 44kV connections where fault levels are higher than any available overcurrent protection device interrupting ratings.

iii) Fault indicators with directional functionality are required for each phase between the PCC and the first pole on the customer owned new line and should be visible from the PCC location.

iv) The DG Owner shall be responsible for the installation, operation and ownership of the load break switch, overcurrent protection device and fault indicators required to be used for the new line.

v) Any additional requirements shall be determined in the CIA.

BACKGROUND INFORMATION

Distribution System reliability considerations dictate the requirement for overcurrent protection device to automatically isolate power system faults on the customer owned line. This is necessary to avoid prolonged interruption of supply to other customers on the feeder for permanent or recurring faults on a single customer-owned line. Fuses, reclosers, circuit switchers or circuit breakers may be used as an overcurrent protection, the selection of which will be determined by the specifics of the Distribution System and the connection configuration of the DG Facilities.

The use of single-phase overcurrent protection device in 3-wire systems might increase the probability of Ferro-resonance. For this reason, a three-phase gang-operated protective device is required for customer owned new line connecting to Hydro One's 3-wire systems.

Fault indicators are required on each phase of the customer owned new line, as a means to quickly identify a faulted phase on the customer's line.

2.1.7 ISOLATION DEVICE

i) A means of electrically isolating the DG Facility from Hydro One's Distribution System shall be provided.

ii) The isolation device shall:

   a) be in compliance with the OESC[2];

   b) be capable of being energized from both sides[3];

   c) plainly indicate whether in the open or closed position[3];

   d) be capable of being opened at rated load (Load Break Switch)[3];

[2] As outlined by the OESC Section 84
[3] In accordance with OESC Section 84-024

e) be located between the Hydro One system and the DG Facility, upstream of all transformers, generation and HV ground sources;

f) be readily accessible by Hydro One[3];

g) not be located in a locked facility;

h) not be located in a hazardous location[4];

i) have provision for being locked in the open position[3];

j) have a manual override;

k) have no keyed interlocks;

l) have contact operation verifiable by direct visible means (be a Visible Break type)[3];

m) conform to OESC Sections 14, 28 and 36 if it includes an overcurrent device[3];

n) be capable of being closed with safety to the operator with a fault on the system[3];

o) be capable of being operated without exposing the operator to any live parts; and

p) bear a warning to the effect that inside parts can be energized from sources on both sides when disconnecting means is open[3].

iii) In addition to the requirements in Item (ii) above, all three phase DG Facility's isolation device shall:

a) be gang operated and disconnect all ungrounded conductors of the circuit simultaneously[5];

b) 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.

c) have a protection interface for tripping if used as a backup for interrupting device failure (HVI Breaker Failure or LVI Breaker Failure).

4 As defined by OESC Section 18
5 In accordance with OESC Section 84-024

iv) If the isolation device is motorized as required by Item (iii)(b) above, it shall be powered from a reliable source such as a DC battery to power a DC motor or via a battery-supplied DC/AC inverter to power an AC motor.

v) If multiple generators are connected at the DG Facility, one disconnect switch shall be capable of isolating all of the generators simultaneously.

vi) Switching, tagging and lockout procedures shall be coordinated with Hydro One.

vii) The DG Owner and Hydro One shall mutually agree to the exact location of the disconnect switch.

BACKGROUND INFORMATION

To ensure a safe and reliable means of electrically isolating the DG Facility from Hydro One's Distribution System, an isolating device that conforms to OESC Section 84 and additional Hydro One requirements is required.

This point of disconnection is required for the purpose of work protection of Hydro One and DG Facility personnel. Operation of the isolation device shall not be a source of injury to the operator during operation, even when closed into a faulted system. It may also be used for breaker fail schemes.

The DG Facility isolation device, if motorized, must have a reliable uninterruptable power source. An AC motor supplied from the AC station service supply may be used to power the motor providing there is an auto-transfer from a DC/AC inverter. For example, if the HV disconnect switch (isolation device) motor is AC rated and powered from the AC station service and if all load derived from the AC station service are considered "non-critical", then, AC power may not be available when the HV disconnect switch is required to operate (example: backup to HVI breaker failure).

If the DG Facility consists of multiple generators, one disconnect switch must be capable of isolating all of the generators simultaneously. There may be other means of meeting this requirement and any proposals must be reviewed by Hydro One.

2.1.8 INTERRUPTING DEVICE RATING

i) All fault current interrupting devices shall be sized appropriately using present and anticipated future fault levels.

ii) The interrupting device used to disconnect generation from Hydro One's Distribution System shall operate fast enough to meet the timing requirement of the quickest protection operation and shall:

a) operate in no more than 160ms, which includes the protection element detection time for DG Facilities not equipped with Transfer Trip; and

b) operate within the required time for DG Facilities equipped with Transfer Trip as shown in Table 13 – maximum interrupting device time is dependent on the speed of Transfer Trip communications.

BACKGROUND INFORMATION

Fault contribution from both the DG Facility and Hydro One's Distribution System shall be used to adequately size all fault current interrupting devices. Hydro One will provide present and anticipated future fault contribution levels from Hydro One's Distribution System.

For generators that have a time variant fault contribution characteristics, the characteristics producing the highest fundamental component fault current shall be used – synchronous and induction generators shall use sub transient reactance to calculate fault contribution. Inverter based generators typically contribute fault current marginally higher than rated full load current (usually 1.2 to 1.5 times the rated load current of the inverter for self-commutated designs and less for line-commutated inverters). Depending on the design, the rotor of double-fed asynchronous motors may be shorted by crowbar action in response to severe faults causing the generator to behave like an induction generator.

The interrupting device shall have a maximum operating time such that when combined with the timings of other protection elements will ensure that the minimum clearing times are achieved. Appendix F contains sample timing diagrams.

2.1.9 PHASING

i) The DG Facility must connect rotating machines as required to match the phase sequence and direction of rotation of Hydro One's Distribution System.

2.1.10 TEMPORARY OVER-VOLTAGE (TOV)

i) Grounding of DG Facilities and connection systems shall be in accordance with Section 2.1.11 and not cause any voltage disturbances.

ii) When connecting to Hydro One's 4-wire Distribution System, TOV that may be caused by the DG Facility connection should not exceed 125% of nominal system voltage (line to neutral) anywhere on the distribution system and under no circumstance shall exceed 130%.

iii) Hydro One may advise on action needed to reduce TOV to limits by specifying the requirement of grounding transformer on the HV side.

BACKGROUND INFORMATION

Connection of DG Facilities causes fault levels, fault current distributions and voltage profiles to change on the Distribution System. The extent of these changes depends on many factors associated with the distribution system and the DG Facility connection. Those factors include but are not limited to:

- Pre-fault voltages of the utility and generator sources;
- Type of fault;
- Fault resistance;
- Utility supply configuration and corresponding source impedances;
- DG Facility supply configuration and corresponding source impedances to the PCC. These are affected by:
  - generator capacity (MVA);
  - generator type(s) – synchronous, asynchronous (induction), inverters and static power converters;
  - the effective net generator impedances (that will likely change during various fault conditions and time periods);
  - generator ground connections;
  - DGIT winding configurations;
  - DGIT capacity and impedances;
  - DGIT ground connections; and
  - DG intermediate transformer impedances (where used).
- Fault location and feeder impedances:

- Location of the fault in relation to the sources (circuit impedances between the fault and the sources); and
- Location of the Distributor and DG Facility sources in relation to each other (circuit impedances between the sources)

A sufficiently comprehensive model of the distribution system and DG Facility connection characteristics is required to predict the extreme worst-case currents and voltages that will occur for various fault conditions. The CIA will determine this and the need for the DG Facility is to ensure that the interconnection will maintain the distribution system's effective grounding and shall not cause TOV to exceed allowable levels.

It should be noted that TOV is an issue not only when the DG Facility is islanded, but may also occur when the DG Facility is still working in parallel with Hydro One's Distribution System before Hydro One's breaker trips.

2.1.11 GROUNDING

i) The grounding of the DG Facility shall not cause overvoltages that exceed the rating of equipment connected to Hydro One's Distribution System.

ii) The grounding of the DG Facility shall ensure that TOV limits in Section 2.1.10 are not exceeded.

iii) The grounding of the DG Facility shall not disrupt the coordination of ground fault protection of Hydro One's Distribution System.

iv) The DG Facility's grounding shall be per manufacturer's recommendation, the OESC and the requirements in Section 2.1.11 of the TIR.

v) The connection of a DG Facility shall not cause the Neutral to Earth Voltage (NEV) to exceed CSA requirements (i.e., less than 10 V rms) on 4-wire multi-grounded distribution system.

vi) In the case of shared-use poles, voltages induced on the under-strung neutral must be minimized so as not to increase NEV.

vii) If the primary HV winding of the DGIT is grounded or a grounding transformer on the HV side of the DGIT is installed, the ground grid of the DG Facility shall be connected to Hydro One's ground grid (neutral).

viii) DG Facilities with a grounded HV DGIT, either utilizing a grounding transformer or a neutral reactor connected to the HV neutral, shall be sized as required in either Item

(ix) below to ensure that TOV limits are not exceeded or Item (x) below to ensure the impact to ground fault protection coordination requirements in Item (iii) above is satisfied.

ix) For DG Facilities connecting to Hydro One's 4-wire Distribution System, TOV is a major concern and the neutral reactor (X_n) or grounding transformer shall be sized by the DG Owner and reviewed during the Connection Impact Assessment based on a Thevenin Equivalent of the Positive (X_{DG1}) and Zero Sequence (X_{DG0}) Reactance of the DG Facility (example: at the Point of Connection with the Point of Connection OPEN) that will result in:

a) For Conventional (Rotating) Generators:

$$1.5 \leq \frac{}{1X} \leq X2.5$$

This will achieve an overall Thevenin Equivalent Positive and Zero Sequence impedance at any point on the feeder with any or all DG Facility sources and Hydro One sources In-Service of:

$$2 \quad /_{1} \quad 3 \text{ and } \quad /_{1X} \; X0.4\text{; or}$$

b) For DG Facilities with an Inverter Interface:

$$0.6\ \text{p.u.} \quad 10\% \text{ and } \quad / \quad \geq X4$$

where 1 p.u. impedance is based on:

1) the total MVA rating of the DG Facility (sum of DGITs MVA ratings) and high side kV rating of the DGIT(s) for Grounding Transformer sizing; or
2) the MVA and high side kV rating of the DGIT for Neutral Reactors sizing.

[Note: DGIT MVA rating is assumed to be approximately equal to the generation capacity. See Appendix C for calculation examples.]

x) For DG Facilities connecting to Hydro One's 3-wire Distribution System, a grounded HV DGIT is not required. However, if the DG Owner decides to have the DGIT grounded, the ground source contribution from the DG shall be limited as follows. The neutral reactor (X_n) or grounding transformer shall be sized by the DG Owner and reviewed during the Connection Impact Assessment based on a Thevenin Equivalent of the Positive (X_{DG1}) and Zero Sequence (X_{DG0}) Reactance of the DG Facility (example: at the Point of Connection with the Point of Connection OPEN) that will result in:

a) For Conventional (Rotating) Generators:

$$/X_{1X} > X8 \quad \text{; or}$$

b) For DG Facilities with an Inverter Interface:

$$/_{1X} > XX24$$

[Note: For (a) above, X_{DG1} is the equivalent of X''_d plus X_t of the DG Facility. For (b) above, X_{DG1} is the reactance of the DGIT. See Appendix C for calculation examples.]

xi) The installation of a wind farm shall not increase the lightning transfer to Hydro One's system.

xii) In wind installations, to limit the exposure of lightning to Hydro One's Distribution System, lightning protection grounding shall be electrically separated from the grounding grid of the wind tower.

xiii) Where the separation in Item (xii) above is not possible or practical, then the ground grids of the towers shall be electrically separated from the DG Facility Station ground grid from the point of view of transferred lightning surges. The latter can be achieved by ensuring that the wind towers are not bonded to the station's ground grid.

xiv) Stand alone studies are required to ensure that GPR meets step and touch potential and OESC requirements.

xv) The report in Item (xiv) above must be submitted to Hydro One.

DESIGN CONSIDERATION

Multi-grounded 4-wire distribution feeders are effectively grounded and the DG Facility shall appropriately size its neutral reactor such that for the entire feeder and for all system conditions the ratio of zero-sequence reactance to positive-sequence reactance ($/X_{1X}$) is positive and less than 3, and the ratio of zero-sequence resistance to positive-sequence reactance ($/X_{1X}$) is positive and less than 1. Further, to restrict ground fault contribution, a lower limit is placed on $/X_{1X}$.

Lightning drainage conductors must be electrically separated from the wind tower's ground grid (> 6 ft). If this is not possible or practical, then the ground grid of the tower shall be separated from the DG Facility Station ground from the point of view of transferred lightning surges. This can be achieved by ensuring that the wind towers are not bonded to the station's ground grid. There are different ways to achieve this, such as ensuring that the cables are not bonding the two systems together (can be achieved by designing a span or section of the line overhead). Separation from a transferred lightning point of view can also be achieved if sufficient lightning drainage is provided between the wind turbine tower and the facility. A study would have to be provided to support such a solution.

2.1.12 INTERCONNECTION TRANSFORMER CONFIGURATION

i) The DG Interconnection Transformer (DGIT) shall not cause voltage disturbances or disrupt co-ordination of distribution system ground fault protection.

ii) The DG Owner shall choose one of the DGIT configuration options outlined in Section 2.1.12.1 if the DG Facility is connecting to Hydro One’s 4-wire Distribution System.

iii) The DG Owner shall choose the DGIT configuration outlined in Section 2.1.12.2 if the DG Facility is connecting to Hydro One’s 3-wire Distribution System.

iv) The DG Owner shall ensure that there is no back feed from the DGIT when the generator is out of service and shall be responsible for all consequences resulting from such back-feeds.

v) The DGIT may supply unbalance current to support the unbalanced load on the feeder even when the generator is out of service. The DG Owner is responsible to ensure the design is adequate to handle the unbalance current. Refer to Requirements in Section 2.2.2.2.

vi) Items (i), (ii) and (iii) above apply to all DG Facilities connecting directly to Hydro One’s Distribution System or indirectly through a hybrid feeder.

vii) Items (i), (ii) and (iii) above may apply to DG Facilities connecting indirectly to Hydro One’s Transmission or Distribution System through an embedded LDC if the connections may negatively impact Hydro One’s system.

BACKGROUND INFORMATION

As per the DSC, Appendix F.2 Section 2, the interconnection transformer shall not cause voltage disturbances or disrupts co-ordination of distribution system ground fault protection. Annex C of CAN/CSA Standard C22.3 No.9-08 discusses different DG interconnection transformer configurations and presents their advantages and disadvantages.

Since the winding configuration of any three phase transformer(s) between the DG Facility and Hydro One will have an impact on the distribution system, both under steady state and fault conditions, Hydro One has analyzed the different options and has standardized the DGIT configuration to a few specific alternatives. This section presents a description of the allowable transformer configurations for the connection of a DG Facility to Hydro One's 3-Wire and 4-Wire Distribution System. Other connections may also be allowed as long as they are electrically equivalent. Hydro One will accept any alternate proposals and if approved, will add them to the available options in this section. Written approval from Hydro One will be required for any alternate configuration. The DGIT may supply unbalance current to support the unbalanced load on the feeder. This unbalance current may be present even if the generator is out of service. The proportion of unbalance load current from the DGIT will vary based on the feeder topology, unbalanced loads, voltage and the DG Facility location.

2.1.12.1 DG FACILITY INTERCONNECTION TO 4-WIRE DISTRIBUTION SYSTEMS

i) The DG Facility shall connect to Hydro One's 4-Wire Distribution System using one of the following options:

   a) Wye-Ground:delta DGIT as shown in Figure 2;

   b) Wye-Ground:wye-Ground with a Delta tertiary DGIT as shown in Figure 3;

   c) Wye-Ground:wye-Ground (LV may be ungrounded) DGIT with an HV Grounding Transformer as shown in Figure 4; or

   d) Delta:wye DGIT with HV Grounding Transformer as shown in Figure 6;

ii) In addition to the DGIT options in Item (i) above, the DG Facility may also connect through a Wye-Ground:wye-Ground DGIT without an HV Grounding Transformer as shown in Figure 5 if generators are solidly grounded and the requirements of Section 2.1.10 and Section 2.1.11 are met. The CIA shall determine whether this option is feasible.

iii) In addition to the DGIT options in Items (i) and (ii) above, the DG Facilities smaller than 1 MVA having generators grounded through an impedance may also connect through a Wye-Ground:wye-Ground or a Delta:wye transformer without installing an HV Grounding Transformer as shown in Figure 7 if the CIA determines that the TOV requirements in Section 2.1.10 are met.

iv) For generation being added to existing critical load installations, such as hospitals and water treatment plants, existing Delta-wye load transformer can be used to connect the generation as shown in Figure 8 provided that the requirements in

Item (vi) below are met and that an HVI is provided to isolate the HV Grounding Transformer from the Distribution System whenever the generation is disconnected from the Distribution System.

v) A neutral reactor in the primary winding of DGIT options in Items (i)(a), (i)(b), (ii) and (iii) above may be necessary to limit the ground short circuit current and shall be sized in accordance with Section 2.1.11 Item (ix).

vi) An HV Grounding Transformer on the HV side of the DGIT shall be required to keep TOV within limits for DGIT options in Items (i)(c), (i)(d) and (iv) above and shall:

a) be sized in accordance with Section 2.1.11 Item (ix);

b) be located on DG Facility side of the HVI;

c) be a zig-zag design;

d) be either solidly connected (not fused) to ensure that the transformer is in service at all times, or if fused, the fuses shall be monitored and the DG Facility's HVI shall be tripped in the event of a failure of the grounding transformer;

e) have the neutral of the grounding transformer connected to Hydro One's neutral conductor; and

f) have adequate protection to provide an alarm when the neutral overcurrent rating of the grounding transformer is exceeded and to automatically remove the grounding transformer from service and disconnect all generation when internal phase or ground faults occur.

vii) The DGIT options in Items (i), (ii) and (iv) above shall require the installation of a high side interrupting device (HVI) in accordance with Section 2.1.13 to ensure that the HV Ground Source is disconnected from Hydro One's Distribution System during abnormal conditions. The requirement of an HVI for the option in Item (iii) above shall be determined in the CIA.

viii) The DGIT's ground shall be connected to Hydro One's neutral conductor.

ix) The DGIT design and installation shall meet all other grounding requirements in Section 2.1.11.

x) The design of the DGIT shall ensure that all Power Quality requirements are adhered to.

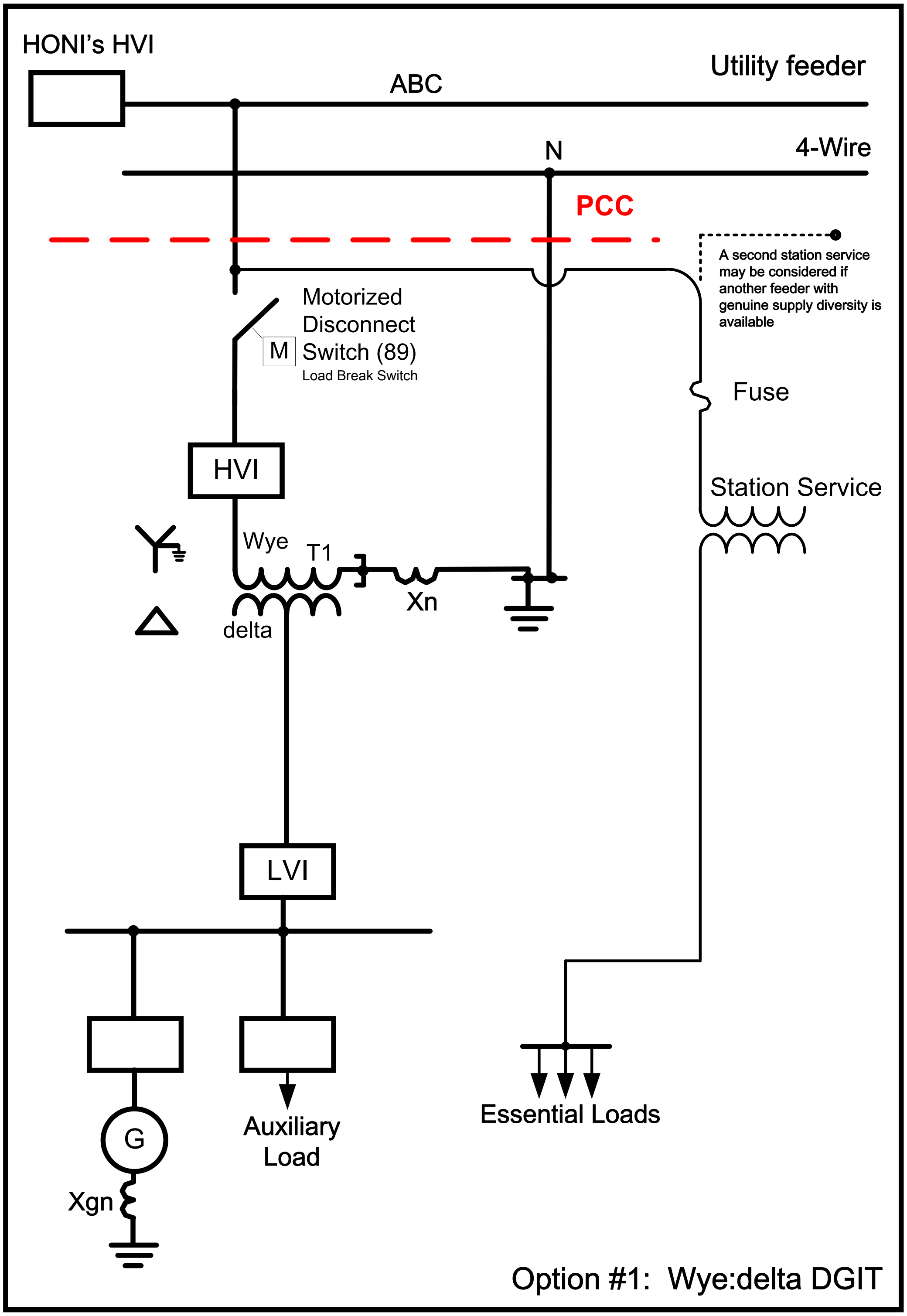


Figure 2: 4-Wire DGIT Option #1

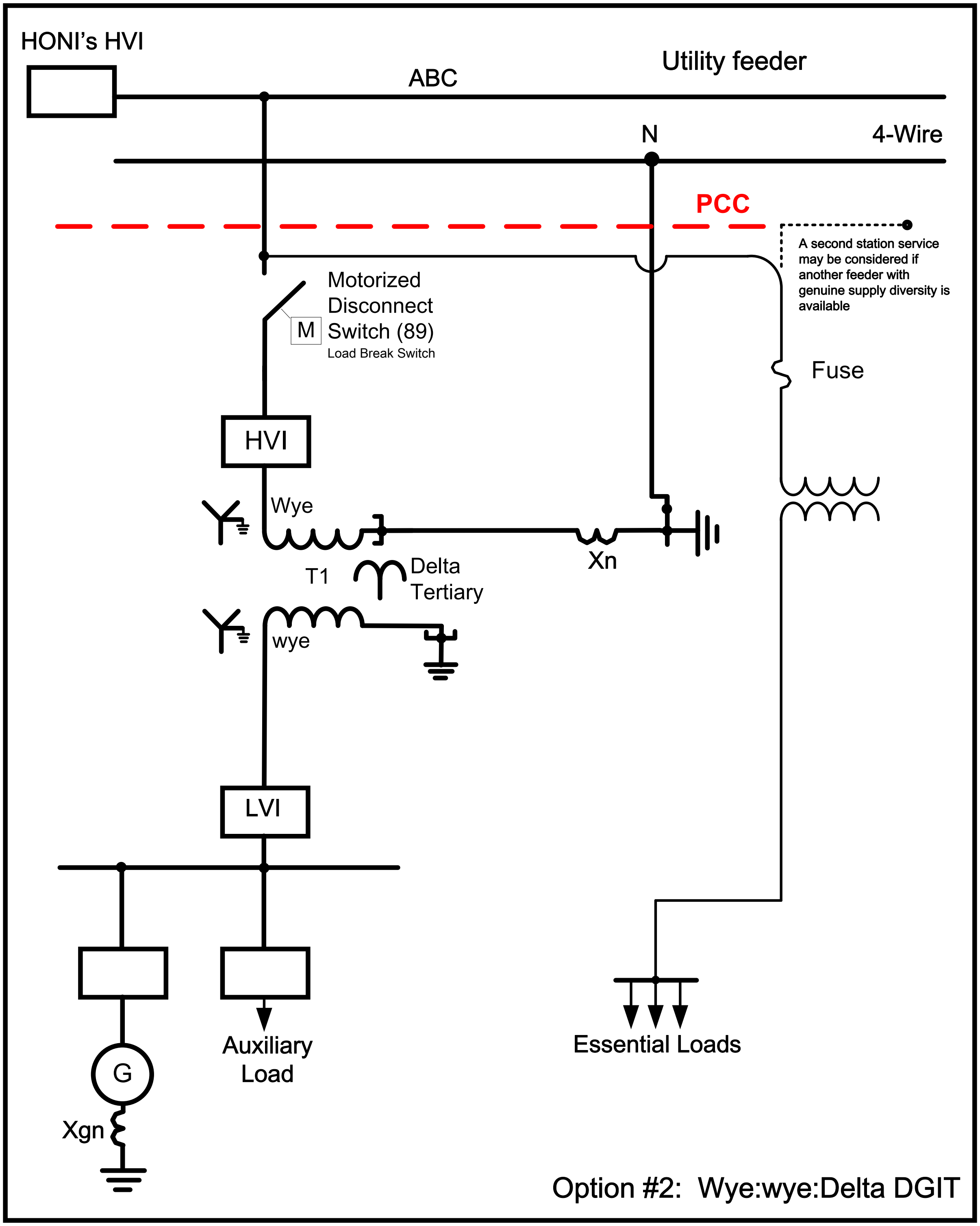


Figure 3: 4-Wire DGIT Option #2

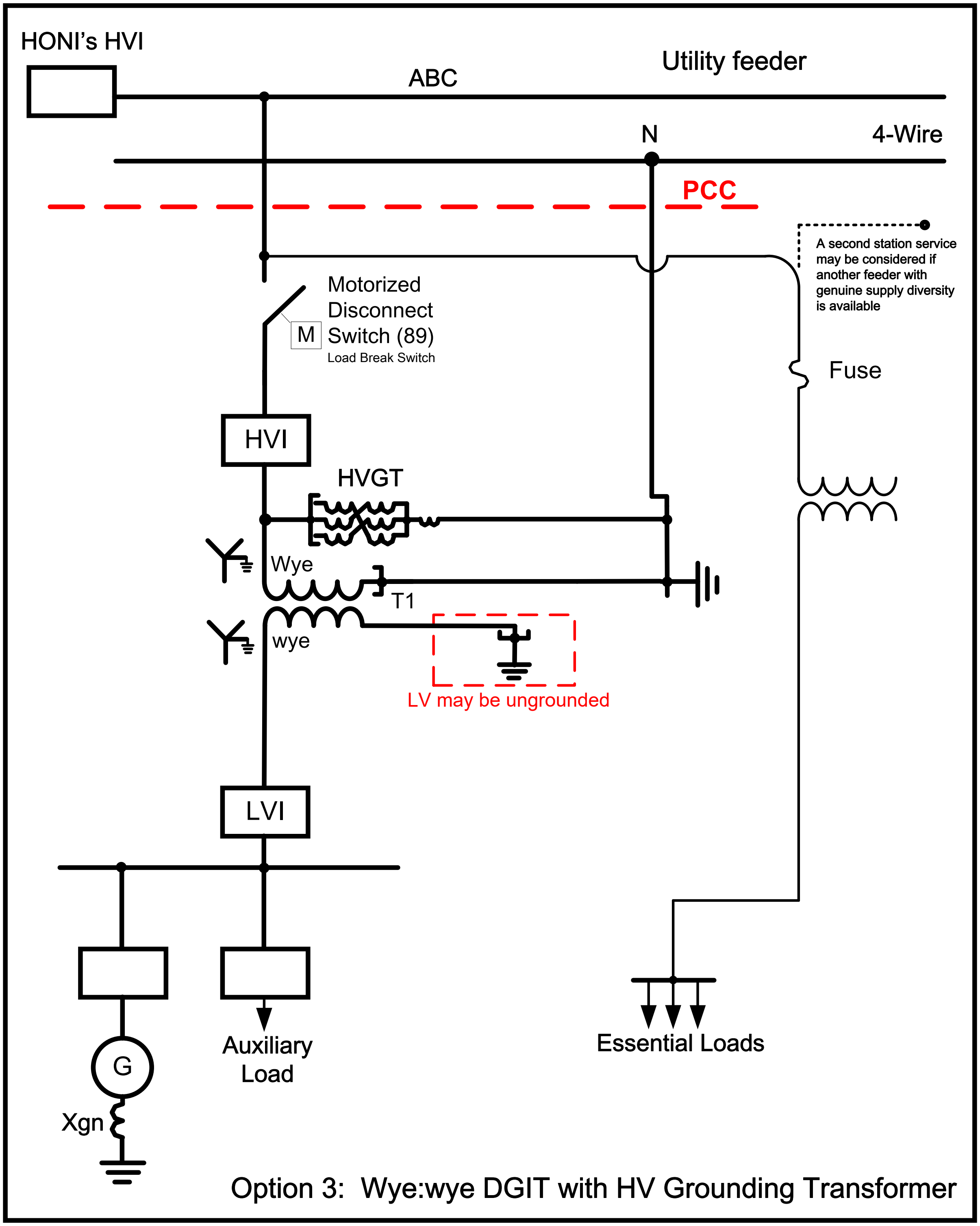


Figure 4: 4-Wire DGIT Option #3

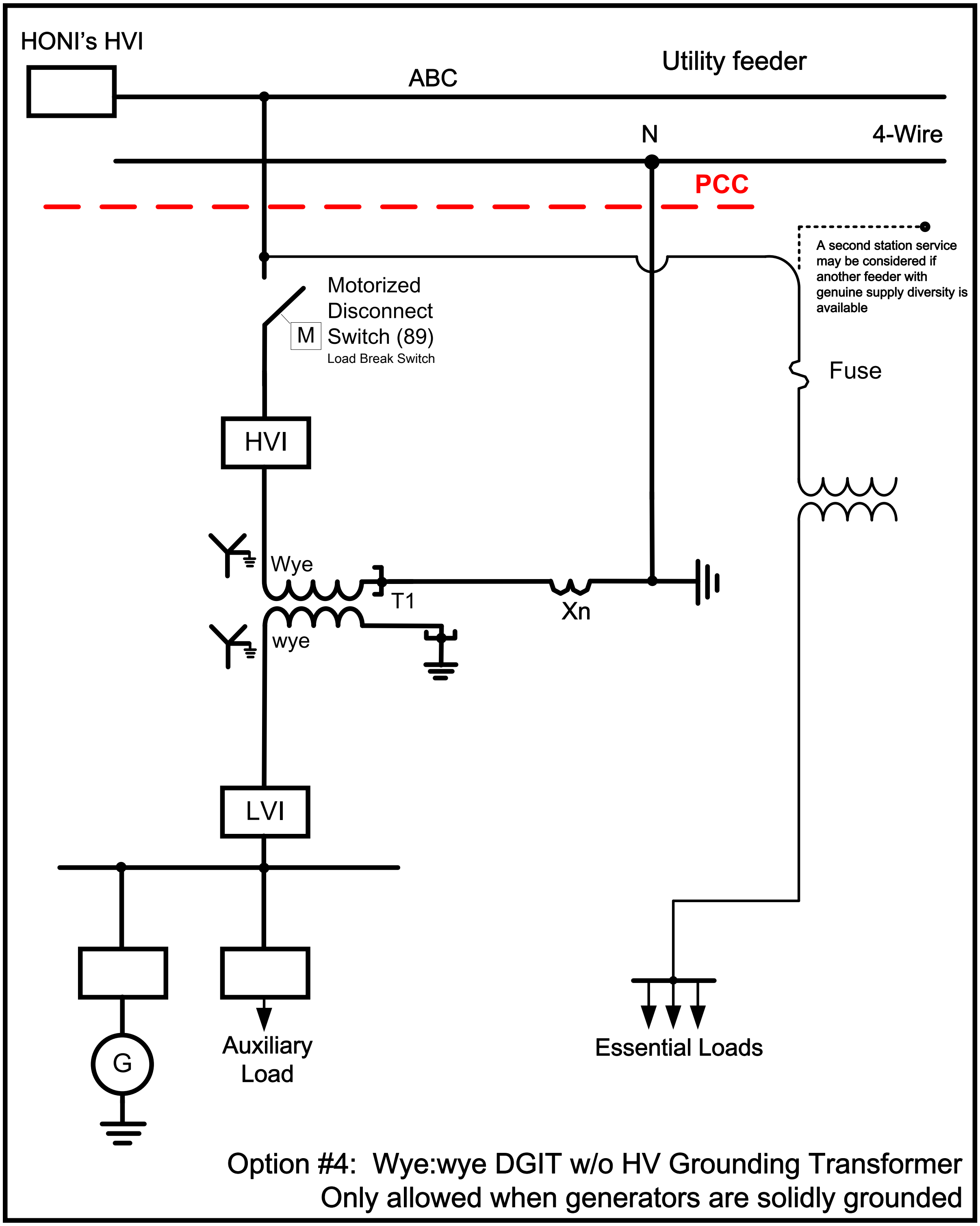


Figure 5: 4-Wire DGIT Option #4

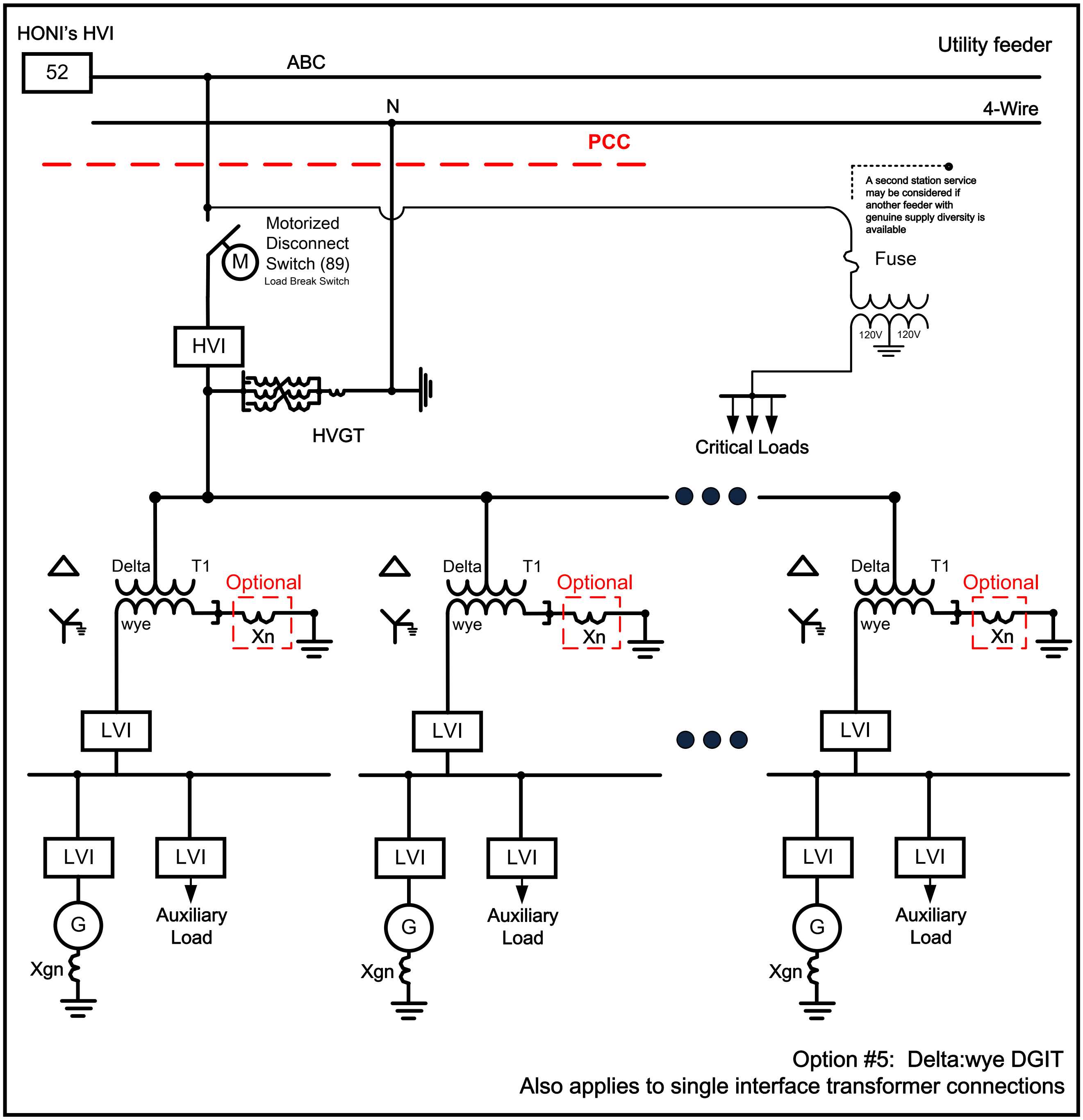


Figure 6: 4-Wire DGIT Option #5

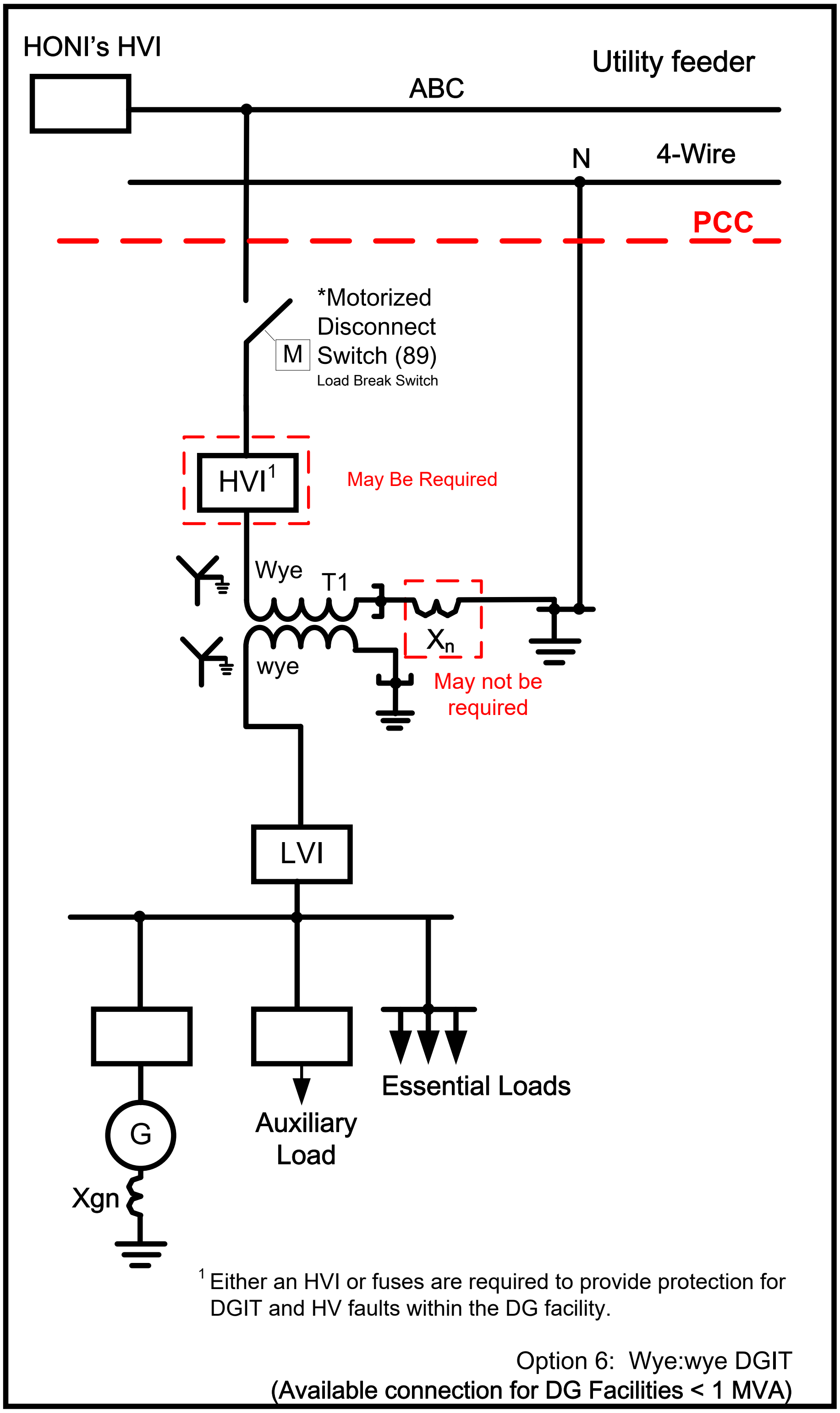


Figure 7: 4-Wire DGIT Option #6

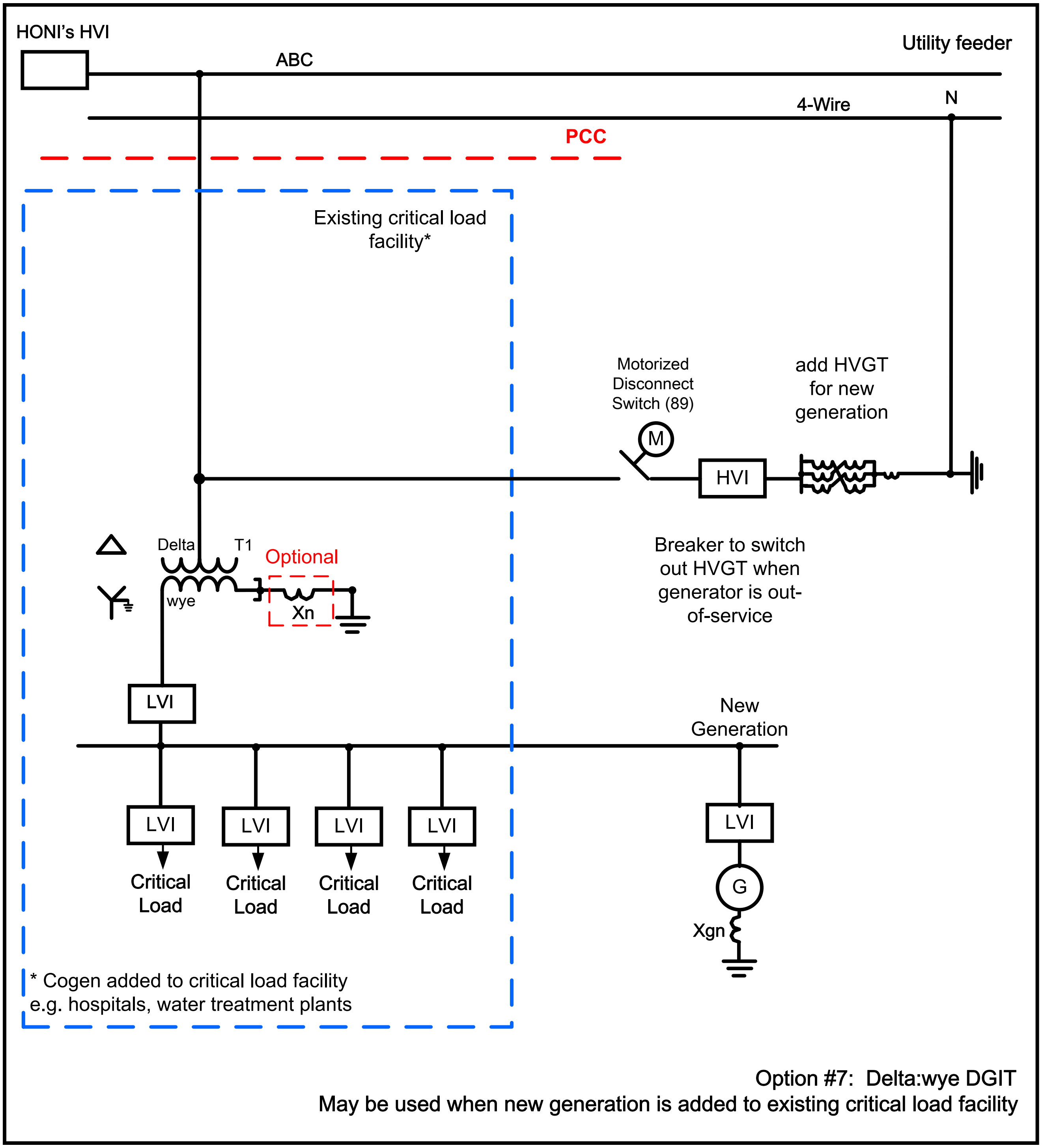


Figure 8: 4-Wire DGIT Option #7

BACKGROUND INFORMATION

HONI requires that interconnections to the 4-Wire distribution system do not cause excess Temporary Overvoltages (TOV) and ground protections to become compromised. To achieve this, HONI requires that DGITs are effectively grounded. This will prevent the damaging TOV associated with high side ungrounded transformer configurations. However, this introduces a HV ground source which desensitizes HONI`s protections and increases ground fault short circuit levels. To minimize these effects, a neutral grounding reactor at the primary winding (HV) may be necessary to limit the ground short circuit current.

When HONI's feeder Low Set instantaneous protection operates, the HV ground sources along with the generators shall be disconnected. This allows the timed overcurrent protection on HONI's distribution system, such as feeder breakers, inline reclosers, and fuses, to detect all faults on HONI's Distribution System and coordinate properly after HONI's supply is reconnected. Please refer to Appendix A.9 for an explanation of HONI's Distribution System protection scheme.

Different options are provided for DG Owners to choose from when selecting the transformer winding configuration for their DG Facility. All are electrically equivalent with the exception of the option provided in Item (iii) for DG Facilities smaller than 1 MVA.

The Wye-Ground:wye-Ground with a Delta tertiary is an option. The delta tertiary is required to limit the harmonic distortion to HONI's distribution system and to limit the TOV's on HONI's distribution system due to the introduction of the DG on the feeder if the generator is ungrounded or high impedance grounded. This configuration should eliminate the need for grounding transformers on both the HV and LV side of the DGIT.

DG Facility installations which utilize multiple transformers that step up the voltage directly to the distribution voltage level and connect to HONI distribution system through a common PCC may wish to utilize a DGIT with a HV Delta winding. This option will require a grounding transformer (zig-zag) to be connected on the HV side of the DGITs to limit the TOV on HONI's distribution system. This grounding transformer shall be sized by the DG Owner and reviewed during the Connection Impact Assessment. Since this makes this configuration electrically equivalent, an HVI is required to ensure all HV Ground Sources are disconnected from HONI`s Distribution System. This option may be preferable for inverter based DG Facilities as it may be more economical to use grounding transformers as opposed to neutral reactors due to the impedance required – Refer to Section 2.1.11 Item (ix) for sizing requirements.

If the option available to only DG Facilities smaller than 1 MVA is chosen, and if there is single phase reclosing upstream of the DG Facility on HONI's distribution system, consideration should be given to use 3 separate single phase transformers. This will eliminate the problems associated with backfeed onto faulted phases due to a shared magnetic core. Therefore in the case of a downed conductor, without the presence of a HVI at the DG Facility to disconnect the transformer, the public would not be put at risk due to magnetically coupled voltage on the conductor.

The design of the DG Facility should take into consideration the possibility of ferroresonance due to the loss of one or two phases and shall take steps to ensure that the DG Facility is protected under such an occurrence.

2.1.12.2 DG FACILITY INTERCONNECTION TO 3-WIRE DISTRIBUTION SYSTEMS

i) The DG Facility shall connect to Hydro One's 3-Wire Distribution System through:

    Delta:wye DGIT as shown in Figure 9

ii) For DGIT configurations that connect the DG Facility to Hydro One's system as a ground source, the DG Facility shall meet the grounding requirements in Section 2.1.11 Item (x).

iii) The design of the DGIT shall ensure that all Power Quality requirements are adhered to.

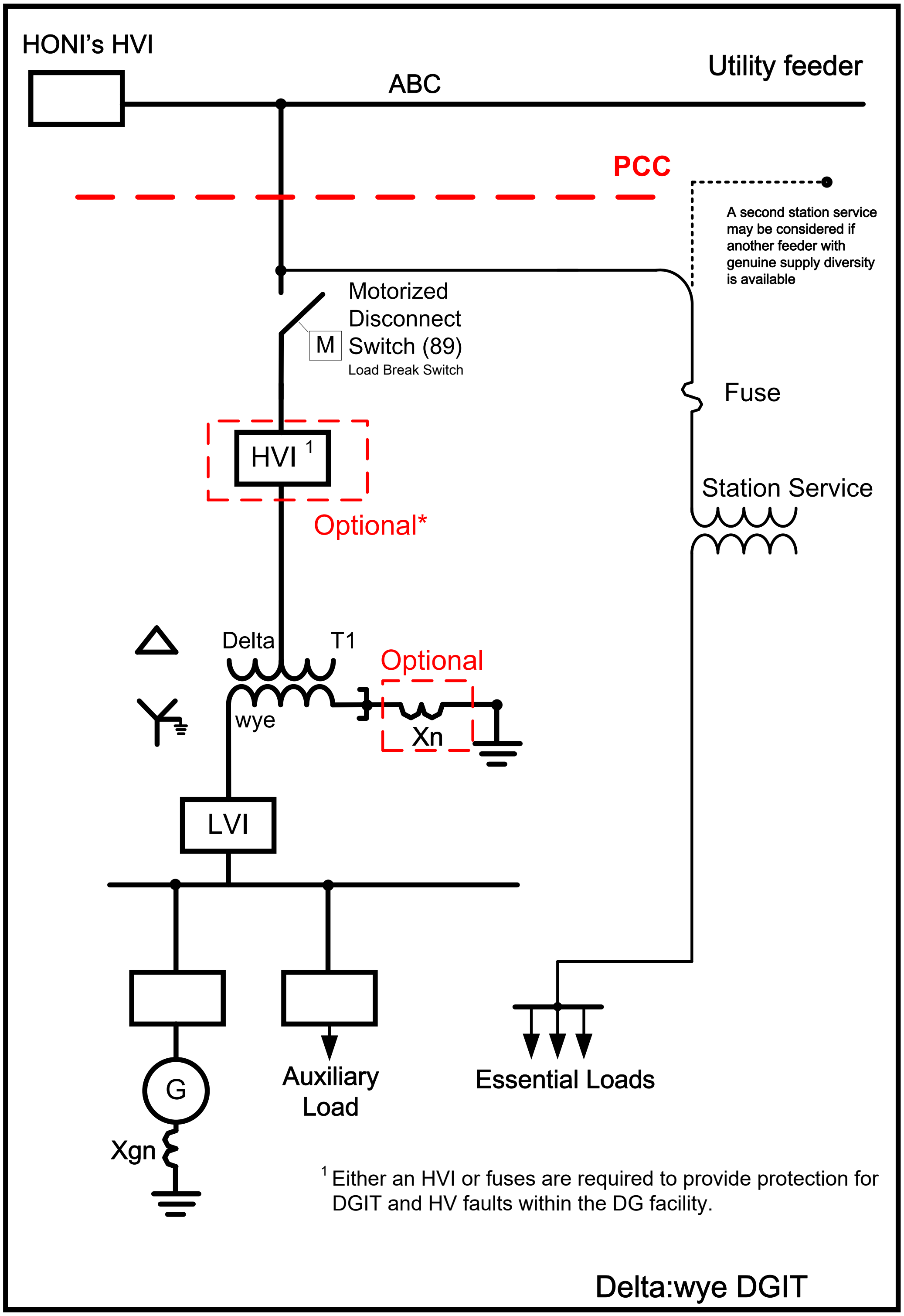


Figure 9: 3-Wire DGIT

BACKGROUND INFORMATION

HONI's 3-Wire Distribution Systems have been designed to withstand phase to phase voltage magnitudes on all phase conductors and thus there is no concern of TOV for these connections. Since TOV is not a problem, HONI does not stipulate the need for an effectively grounded DGIT. If one is chosen, it shall be sized as required in the grounding requirements in Section 2.1.11 Item (x). An HVI shall be required in this case. In the absence of a HVI, an interrupting device(s) shall be installed on the LV side of the DGIT.

The design of the DG Facility should take into consideration the possibility of ferroresonance due to the loss of one or two phases and shall take steps to ensure that the DG facility is protected under such an occurrence.

Protection systems shall be designed accordingly to ensure that ground faults on HONI's distribution system are detected.

2.1.13 HIGH VOLTAGE INTERRUPTING DEVICE (HVI)

i) The DG Facility shall be equipped with a High Voltage Interrupter (HVI), with a protection interface for tripping, upstream of all interconnection transformers and HV ground sources if:

   a) the DG Facility is connecting to Hydro One's 4-wire Distribution System and is grounded in accordance with Section 2.1.11 Item (ix); or

   b) the DG Facility is connecting to Hydro One's 3-wire Distribution System and is effectively grounded or is grounded in accordance with Section 2.1.11 Item (x).

ii) DG Facilities at critical load installations, such as hospitals and water treatment plants, interconnecting to Hydro One's 4-wire Distribution System using the DGIT option in Section 2.1.12.1 Item (iv) shall be equipped with an HVI, with a protection interface for tripping, upstream of the HV Grounding Transformer.

iii) DG Facilities < 1 MW, connecting to Hydro One's 4-wire Distribution System through a Wye-Ground:wye-Ground transformer may be exempt from the requirement in Item (i) above if the CIA determines that:

   a) ground fault source contribution from the DG Facility does not cause coordination problems with Hydro One ground protections; and

   b) the installation does not contain HV grounding transformers.

iv) If the DG Facility does not require an HVI, a low voltage interrupter(s) must be provided to disconnect the DG Facility's generation from Hydro One's Distribution System.

v) The HVI status must be monitored.

vi) The HVI shall be sized properly to account for present and future anticipated fault levels.

vii) Breaker fail protection for the HVI shall be in accordance with requirements in Section 2.3.4.

viii) The HVI's interrupting time shall be in accordance with the timing requirements in Section 2.1.8.

BACKGROUND INFORMATION

NOTE: For the purpose of the TIR, the term HVI will refer to interrupting devices on Hydro One side of the DG Interconnection Transformer (DGIT) – whether it is high voltage or medium voltage.

DG Facilities connecting to Hydro One's 4-wire distribution system require that the HV ground source is removed and thus, have a need for a high side interrupter. The only exception is for DG Facilities smaller than 1 MW which are connected through typical load transformers (Wye-Gnd:wye-Gnd) if it can be shown that they will not negatively affect Hydro One's protection systems. This connection is one of the options shown in Section 2.1.12.1 Item (iii) and is allowable only if the CIA determines that TOV is not a concern with the specific DG Facility.

DG Facilities connecting to Hydro One's 3-wire distribution system through an HV Delta DGIT without the use of a grounding transformer do not require an HVI as no ground source is present that needs to be removed. For all other connections, an HVI is required. More information on allowable DGIT configurations and grounding requirements can be found in Section 2.1.12 and Section 2.1.11 respectively.

This requirement is driven by the configuration of the DGIT and the need to remove the additional HV ground source from the distribution system before the 1st reclose to ensure that the DG Facilities will not adversely affect overcurrent protection devices on Hydro One's distribution system. The feeder and DG Facility HVI will be tripped for feeder faults or feeder islanding conditions (feeder breaker trips instantaneously and independently of DG Facility HVI tripping). Before the first reclose, all the generators and HV ground sources on the distribution feeder shall be disconnected from the feeder. Upon reclose, the feeder 51 & 51N timed overcurrent devices will co-ordinate with reclosers and lateral fuses on Hydro One's Distribution System since all current infeeds from the generators and the HV ground source are removed. Requirements for disconnection and reconnection to Hydro One's Distribution System following momentary and permanent faults can be found within Sections 2.4.6, 2.4.7 and 2.4.8.

An HVI is also required to prevent back-feed whenever single phase switching can occur upstream of the DG Facility on Hydro One's Distribution System. Refer to Appendix A.9 for more information regarding Hydro One's Distribution System protection practices and standards.

2.1.14 STATION SERVICE FOR ESSENTIAL LOADS

i) Wherever genuine supply diversity is possible, at Hydro One's sole discretion, a second connection for AC station service from another feeder may be allowed to supply essential loads (such as station battery).

ii) The station service in Item (i) above, shall not be electrically connected to the DG Facility's electrical system that is associated with the power transfer from the DG Facility to Hydro One's Distribution System.

iii) The station service load shall not impose operating restrictions on Hydro One's system when either the Motorized Disconnect Switch (Isolation Device – Section 2.1.7) or the HVI is opened.

iv) The station service shall comply with all required load connection standards.

v) The station service shall be in compliance with all metering standards and regulations.

vi) Station GPR shall not be transferred to the neutral of the LV system supplying station service for critical loads.

vii) A backup generator may be used to satisfy Item (i) above.

BACKGROUND INFORMATION

The DG Owner might classify loads at the DG Facility as being either "critical" or "non-critical" based on the outage frequency and expected duration of each outage. "Critical" loads may only tolerate a momentary loss of power and may include such loads as battery charging equipment, emergency lighting or equipment supplying safety or shutdown systems. The DG Owner may not deem any loads at the DG Facility as being "critical" for their operation.

The intent of the above requirements is to make the DG Owner be aware that the HVI at the DG Facility will be tripped from time to time, typically to clear faults on the distribution circuit, and may be out-of-service for longer periods during maintenance or severe disturbances of the distribution system. The HVI at the DG Facility will be required to remain open until the distribution circuit is re-energized and after the staggered restoration delay has expired as per Section 2.4.7. The DG Owner should recognize and accept these extended outages if all DG Facility's loads are supplied from the LV side of the DGIT. The DG Owner may also consider a backup generator to supply critical loads as an alternative to a dedicated station service supply.

If a separate station service AC service power source is obtained from either Hydro One or a local distribution company, the DG Owner shall ensure that the above station service AC power source cannot be electrically connected to the DG Facility's electrical system that is associated with the power transfer from the DG Facility to Hydro One's distribution system (example: the intent is to prevent reverse power from the DG Facility to the station service AC supply source and vice versa).

2.1.15 BATTERIES/DC SUPPLY

i) Batteries shall be provided and shall have adequate capacity to ensure that all protection functions operate when the main source of power fails.

ii) They shall remain operational for the time required for protection functions to operate properly and disconnect the DG Facility from Hydro One's Distribution System. They shall be capable of sustaining continuous telemetry about the DG Facility connection status and DGEO signals.

iii) Items (i) and (ii) above shall be implemented by using batteries and chargers connected to the main service supply or by using an uninterruptable power supply with sufficient capacity for the application.

iv) The battery voltage shall be monitored and upon failure, the protection scheme shall be considered failed and the DG Facility's generation and HV ground sources shall be disconnected from Hydro One's Distribution System.

v) Relays connected to the DC supply shall not be subjected to sustained overvoltages – if there is a possibility that the DC rating of the equipment will be exceeded, steps shall be taken to ensure that DC voltage limiting devices be installed at each relay.

vi) Dual station batteries shall not be required for protection and control equipment.

vii) Protection systems designed to back each other up, shall be supplied by physically separated and protected (i.e. fused) DC Circuits.

viii) Circuit breakers and the DG Facility's Interrupting Device shall be powered by separate and dedicated DC Circuits.

ix) Separate and independent means are to be used for tripping the DG Facility's Interrupting Device and the DG Facility's Isolation Device (when motorized – See Section 2.1.7 Item (iii)(b)).

x) Upon low voltage (DC) conditions, the protections shall trip the generators and all HV Ground Sources.

xi) Capacitors shall not be used as the primary means to store energy in lieu of batteries.

2.1.16 FAULT LEVELS

i) Maximum fault levels must be maintained within the limits set by the Transmission System Code (TSC) as shown in Table 2 and the connection of DG Facilities shall not cause these limits to be exceeded.

Table 2: TSC Maximum Fault Levels[6]

Fault Levels	**Requirement**		
Maximum fault values are symmetrical fault values. Higher values may exist for short times during switching	Nominal Voltage (kV)	Maximum Three-Phase Fault (kA)	Maximum SLG Fault (kA)
	44	20	19 (usually limited to 8 kA)
	27.6 (4-wire)	17	12
	27.6 (3-wire)	17	0.45
	13.8	21	10

2.1.17 INSULATION COORDINATION

i) The DG Facility shall be protected against lightning and switching surges.

ii) Surge arresters shall be located as close as possible to the equipment they protect and shall have adequate ratings to withstand the TOV during single-line-ground faults (Hydro One's Surge Arrester ratings are shown below in Table 3).

6 Extract from Ontario Energy Board - Transmission System Code Appendix 2 – Transmission System Connection Point Performance Standards

iii) Insulation coordination shall conform with CAN/CSA C71-1-99-1 and CAN/CSA C71-1-99-2.

Table 3: Surge Arrester Ratings

Hydro One Distribution System Surge Arrester Ratings		
System Voltage (kV rms)	Arrester MCOV (kV rms)	Duty Cycle Rating (kV rms)
2.4 / 4.16	2.55	3
4.8 / 8.32	5.1	6
7.2 / 12.5	7.65	9
8.0 / 13.8	8.4	10
14.4 / 24.9	15.3	18
16.0 / 27.6	17	21
44*	39	48

*Three-wire sub-transmission from effectively grounded-wye supply

BACKGROUND INFORMATION

Unavoidable transient overvoltages might occur on the Distribution System and the DG Facility due to lightning and switching surges. The DG Facility equipment must be protected as required against these voltage stresses to prevent equipment damage and to prevent the propagation of these transients into Hydro One's Distribution System. Overvoltage protection usually includes using station and line shielding against direct lightning strikes and surge arresters for all wound equipment.

2.1.18 INSTRUMENT TRANSFORMERS FOR USE IN PROTECTION SYSTEMS

i) All instrument transformers used in DG Facilities for protections shall meet the requirement of CSA-C60044-6 or IEEE C57.13.

2.1.19 POWER QUALITY MONITORING DEVICE

i) DG Facilities > 250kW shall be equipped with a Power Quality (PQ) monitoring device capable of providing the reports required in Section 2.7.2.

ii) The PQ monitoring device shall have the ability to perform sampling at the rate of 256 samples / cycle (~15 kHz) for a minimum of 96 cycles. This will ensure that the device is capable of recording voltage and current harmonics up to the 50^{th} harmonic (3 kHz), impulsive transients in the milliseconds range (monitoring possible to at most 7 kHz), and low frequency oscillatory transients (<5 kHz).

iii) The instrument transformers used for PQ monitoring shall be capable of monitoring transients up to 7 kHz, and swells up to 1.2 p.u. for a period of 1 minute.

iv) PQ monitoring applies to phase voltages, neutral to ground voltage and phase currents.

2.1.20 PROTECTION FROM ELECTROMAGNETIC INTERFERENCE (EMI)

i) EMI shall not cause the protection, control and communication functions of the DG Facility interconnection to fail, change state, misoperate or provide inaccurate information.

ii) The DG Facility interconnection must have the capability to withstand electromagnetic interference (EMI) environments in accordance with:

   a) ANSI/IEEE Std. C37.90.2, "IEEE Standard for Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers."; or

   b) CAN/CSA-CEI/IEC 61000-4-3, using Level X, 35 V/m, in accordance with IEEE C37.90.2.

iii) The DG Owner shall provide documentation to show compliance with Item (ii)(a) or (ii)(b) above.

2.1.21 SURGE WITHSTAND

i) The protection, control and communication equipment of the DG Facility interconnection system shall not fail, misoperate, or provide misinformation due to voltage or current surges[7].

ii) The interconnection system shall have the capability to withstand voltage and current surges in accordance with the environments defined in IEEE/ANSI Std. C62.41.2, "IEEE Recommended Practice on Characterization of Surges in Low-Voltage (1000 V and Less) AC Power Circuits" or IEEE Std. C37.90.1, "IEEE Standard for Surge Withstand Capability (SWC) Tests for Relays and Relay Systems Associated with Electric Power Apparatus – Description."

[7] CSA Std. C22.3 No.9-08 Section 7.4.18 provides more detailed information.

2.1.22 DG FACILITY ACCEPTANCE

i) The DG Owner must have a professional engineer licensed in the Province of Ontario declare (stamp and seal) that the DG Facility has been designed, tested and constructed in accordance with the requirements of the TIR, Hydro One's site-specific requirements, prudent utility practice and all applicable standards and codes.

ii) The DG Owner shall provide the proposed design of all power equipment, protection, control, and metering systems used at the DG Facility to Hydro One for review.

2.1.23 GENERATORS PARALLELING FOR 6 CYCLES OR LESS (CLOSED TRANSITION SWITCHING) [8]

i) The generator shall be exempt from all requirements in the TIR except for the requirements in Items (ii) and (iii) below.

ii) DG Facilities paralleling for 6 cycles or less shall have the following protections:

  a) Under-voltage protection to ensure that the generator is not capable of energizing Hydro One's Distribution System if it is de-energized; and

  b) A 6 cycle timer to ensure that the DG Facility will not parallel with Hydro One's Distribution System for more than 6 cycles.

iii) Synchronization facilities, where required, must follow the requirements specified in Section 2.4.4.

2.1.24 PROVISION FOR FUTURE CHANGES

i) The DG Owner shall be responsible to stay aware of future changes to the business environment and technical requirements.

ii) The DG Owner shall make any necessary changes to the DG Facility promptly in response to:

  a) New or revised standards;

  b) New or revised codes;

  c) Legislation changes; and

  d) Safety concerns.

[8] As per CSA 22.3 No.9-8 section 7.4.13 Momentary closed transition switching

iii) The DG Owner may be responsible for some or all costs associated with the changes in Item (ii) above.

2.2 PERFORMANCE REQUIREMENTS

2.2.1 GENERAL

i) The connection of the DG Facility must not materially compromise the reliability or restrict the operation of Hydro One's Distribution System.

ii) The connection of the DG Facility must not degrade power quality below acceptable levels listed in Section 2.2.2 (Power Quality Requirements).

iii) The DG Owner shall ensure that the facility is equipped to measure, record and report on performance related events to demonstrate compliance with the applicable sections of the TIR.

iv) If the DG Facility is found to significantly deteriorate the performance of the Hydro One's Distribution System, it shall be disconnected from Hydro One's Distribution System until appropriate measures are taken to mitigate the negative impacts.

2.2.2 POWER QUALITY

2.2.2.1 VOLTAGE

i) The DG Owner shall ensure that the operation of the DG Facility does not have an objectionable impact on voltage at the PCC or the interconnected feeder and shall not cause any violation of CSA Standard CAN3-C235-83 "Preferred Voltage Levels for AC Systems, 0 to 50,000V Electric Power Transmission and Distribution" along the entire interconnected feeder.

ii) PCC voltage shall be maintained within 0.94~1.06 p.u. and shall not be lower than pre-connection voltage.

iii) The DG Facility shall not actively regulate the voltage at the PCC. Voltage at the PCC shall be maintained within acceptable limits by following the requirements in Item (vii) below.

iv) Voltage variations at the PCC shall be limited in accordance with the "Voltage Fluctuations (Flicker) Requirements" in Section 2.2.2.3.

v) At the feeder level, DG Facility shall not contribute to short-term voltage fluctuation anywhere on the feeder by more than 1%[9].

vi) At the station level, all DG Facilities connected to the TS/DS shall not collectively contribute to short-term voltage fluctuation at the station LV bus by more than 1%[10].

vii) Tripping of all DG Facilities connected to the station shall not cause abrupt voltage change to result in a voltage above 110% of nominal bus voltage, or less than 90% of nominal bus voltage, after a single contingency and before the station ULTC /feeder VR operates[11].The operating power factor of the DG Facility at the PCC shall be as required in Section 2.2.2.6 Item (v).

viii) During normal operation, the DG Facility shall be loaded and unloaded gradually to allow adequate time for regulating devices on Hydro One's Distribution System to respond and avoid excessive voltage fluctuations.

ix) The DG Facility shall protect itself from abnormal voltage conditions which the distribution system is subjected to. These may include but are not limited to:

a) voltage transients; and

b) sags and swells caused by lightning, switching, faults, and the loss or switching of customer loads.

x) Insulation levels and protective equipment at the DG Facility shall be capable of withstanding abnormal voltages from Hydro One's Distribution System.

BACKGROUND INFORMATION

Hydro One's station LV bus voltages are regulated within 1.035~1.055 p.u. regardless of load levels. This ensures that the voltage anywhere in the feeder, including the PCC, is within 0.94~1.06 p.u. of the nominal voltage under normal operating conditions. To conform to the existing practice, DG Facilities shall not decrease the pre-connection PCC voltages under all normal operating conditions. During abnormal conditions, voltage variations may exceed the values.

Hydro One's Distribution System was designed to operate for unidirectional power flow (flowing from the substation to the customers). Voltage regulating devices were designed to correctly operate under these conditions. However, with the addition of DG Facilities

[9] Operational and power quality requirement
[10] Operations requirement
[11] IESO requirement (Ontario Resource and Transmission Assessment Criteria Section 4.3)

into the system, the power flow can be reversed when the DG Facility is supplying power. This may inhibit the voltage regulators to properly regulate the voltage on the feeder. If there is a possibility of reverse power flow, regulating devices (line voltage regulators, regulating stations and transformer under-load tap changers at the Transformer Station (TS) or Distribution Station (DS)) on Hydro One's distribution system may need to be either upgraded or replaced with suitable devices that allow bi-directional flow. Note: Hydro One operates all voltage regulating devices on its distribution system to 125V ±1.5V on a 120V base.

Without DG Facilities, the short-term voltage fluctuation on Hydro One feeders are well below 1%, or half of the dead band of voltage regulating facilities. This ensures the voltage regulating facilities respond only to necessarily voltage fluctuations and the quality of supply to customers during normal (non-emergency) operating conditions. Existing DG Facilities connected to Hydro One's system have shown continuous minute-to-minute power fluctuations in the range of 10%~30% of their ratings and this would cause higher levels of voltage fluctuation. In order to maintain similar duty imposed on the voltage regulating facilities, and similar quality of supply to the customers, DG Facilities shall not contribute to feeder voltage short-term fluctuation by more than 1%.

The post-tripping voltage requirement of the DG Facility is consistent with the Transmission System Code and the IESO System Impact Assessment criteria. DG Facilities that do not have ride-through capability are likely to trip off due to a feeder fault close to the Station's LV bus, regardless of the feeder to which the DG Facilities are connected. This requires that reactive power drawn by the DG Facility at a given power output level and therefore lost immediately after the tripping of the DG Facility, should be minimized to prevent excessive voltage change before ULTC/feeder VR tap changers can react.

2.2.2.2 VOLTAGE AND CURRENT UNBALANCE

i) The DG Facility shall be capable of operating under existing unbalance conditions.

ii) The DG Facility shall not cause deterioration of existing unbalance voltage and current conditions at the PCC and in the distribution system.

iii) A single phase generator shall not negatively impact the unbalance of the nearest three-phase distribution system.

iv) The DG Facility shall protect itself from highly unbalanced voltages and currents, especially when connected to Hydro One's Distribution System where single phase reclosing is used.

v) The DG Facility and its interconnection transformer's design shall take into consideration the unbalance current it may supply to the unbalanced load on the feeder.

vi) Single phase generators shall not cause an unbalance of greater than 2% when connected alone.

vii) If multiple single phase generators are installed, they shall be connected so that an equal amount of generation is applied to each single phase of the distribution line, and this balance shall be maintained if one or more of the generating units go offline.

BACKGROUND INFORMATION

Voltage and current unbalance are normal on many distribution feeders as they supply many single phase loads and thereby all three phases are never equally loaded. Phase voltage unbalance of 2% and phase current unbalance of 10-20% of total feeder load is common. Unbalanced loads that result in unbalanced phase voltages and currents can cause high neutral currents, negative sequence voltages and currents, zero sequence voltages, thermal overloading of transformers and three-phase motors, and can cause protective relaying to mis-operate.

To protect Hydro One's distribution system and customers, the DG Facility must not further deteriorate existing unbalance conditions at the PCC and the distribution system. The phase-phase voltage unbalance at the unloaded generator terminals of three-phase DG Facilities must not be greater than 1%. The DG Facility and its interconnection transformer's design shall take into consideration the unbalance current it may supply to support the unbalanced load on the feeder. This unbalance current may be present even if the generator is out of service. The proportion of unbalance load current from the DGIT will vary based on feeder topology, unbalanced loads, voltage and DG location. During abnormal conditions such as faults and single pole reclosing, the unbalance may be very high (current unbalance may be significantly higher than 20%) and it is up to the DG Owner to ensure that the DG Facilities are protected from damage due to unbalance.

Single phase DG Facilities connected to a single phase of Hydro One's distribution system are limited in size (kVA rating) due to the potential impact they may have on distribution system voltage unbalance.

2.2.2.3 VOLTAGE FLUCTUATIONS (FLICKER)

i) The DG Facility shall not create objectionable flicker for other customers on Hydro One's Distribution System.

ii) The voltage dip at the PCC should not be more than 4% on connecting the single largest generation unit in the facility and should remain within 10% of nominal voltage when the entire DG Facility and all other DG Facilities on the interconnected feeder trip.

iii) Item (i) above shall include flicker caused by energization inrush.

iv) The DG Owner shall take steps to make sure that flicker requirements in Items (i) and (ii) are met - may need to add loss of synchronism protection, stagger generator energization, etc.

v) The DG Facility shall conform to the flicker requirements in CAN/CSA C61000-3-7 and meet the Pst and Plt limits shown below in Table 4.

Table 4: P_{st} and P_{lt} Flicker Limits

	27.6/25/13.8/12/8/4 kV	44kV
P_{st}	0.9	0.8
P_{lt}	0.7	0.6

Source: CSA/CAN C61000-3-7

vi) Flicker measurements shall be conducted by the DG Owner using a device that conforms to CAN/CSA-C61000-4-15 if requested by Hydro One. Hydro One shall request this measurement if flicker complaints are received in the surrounding area.

vii) Induction generators and inverter-based generators that do not produce fundamental voltage before the paralleling device is closed, and double-fed generators whose excitation is precisely controlled by power electronics to produce a voltage with magnitude, phase angle, and frequency that match those of the distribution system shall be tested to determine the maximum startup current[12]. The results shall be used, along with the Distribution System source impedance for the proposed location, to estimate the starting voltage magnitude change and

12 The DG Owner may use the generator manufactures data as opposed to actual site tests. However, the DG Owner must ensure that the maximum startup current does not violate the flicker requirements above.

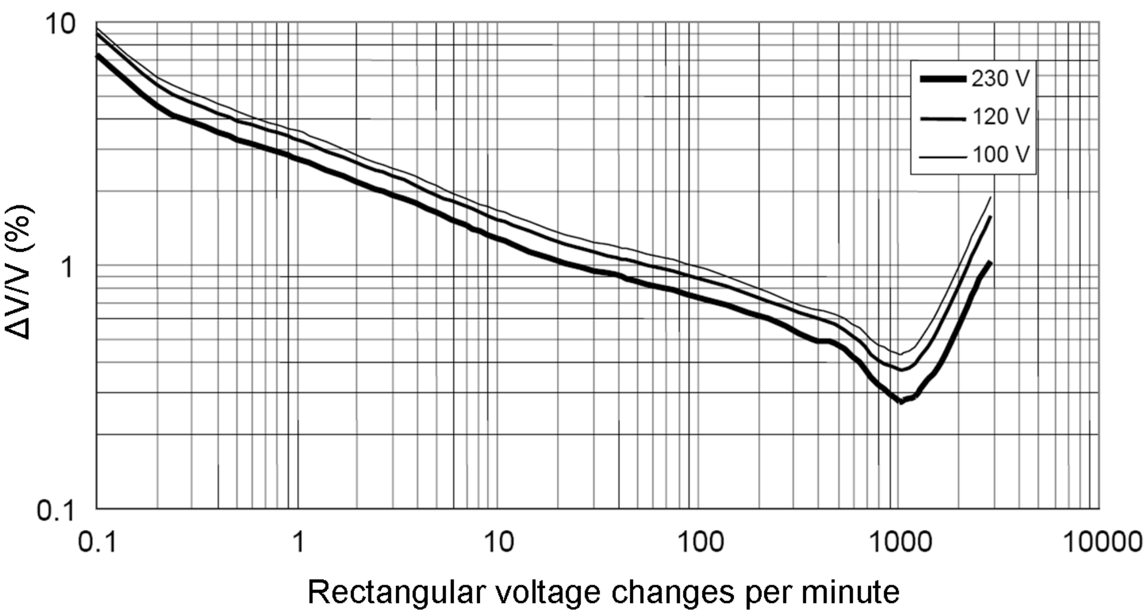
verify that the unit will not cause a voltage fluctuation at the PCC greater than ± 4% of the prevailing voltage level of the distribution system at the PCC.

viii) Induction generators may be connected and brought up to synchronous speed by direct application of rated voltage provided that they meet the requirement of voltage drop given above and/or they do not exceed flicker limits at the PCC. Otherwise, other methods such as reduced voltage starting or speed matching using the prime mover prior to connection must be used to respect these voltage drop and flicker limits.

ix) Large DG Facilities with multiple generator units, shall stagger the generator reconnections to Hydro One's Distribution System to meet the above requirements.

BACKGROUND INFORMATION

The following graph in Figure 10 supplements the Table 4 presented above.



Note – Two consecutive voltage changes (one positive and one negative) constitute one "cycle", i.e., two voltage changes per second mean a 1 Hz fluctuation

Figure 10: IEC/CSA Standard for Flicker

2.2.2.4 VOLTAGE AND CURRENT HARMONICS

i) The DG Facility shall not inject harmonic current that causes unacceptable voltage distortion on Hydro One's Distribution System.

ii) The DG Facility shall follow the requirements of CAN/CSA C61000-3-06.

iii) The DG Facility shall operate within the Voltage distortion limits as indicated in Table 5 and Table 6 below.

Table 5: Voltage Distortion limits for Odd Harmonics

Odd Harmonics Non Multiples of 3			Odd Harmonics Multiples of 3		
	Harmonic Voltage (%)			Harmonic Voltage (%)	
	4-27.6kV	44kV		4-27.6kV	44kV
5	5	2	3	4	2
7	4	2	9	1.2	1
11	3	1.5	15	0.3	0.3
13	2.5	1.5	21	0.2	0.2
17	1.6	1	>21	0.2	0.2
19	1.2	1			
23	1.2	0.7			
25	1.2	0.7			
>25	$0.2\ \ \mathrm{X}0.5\frac{\mathrm{X}25}{\mathrm{X}h}$	$0.2\ \ \mathrm{X}0.5\frac{\mathrm{X}25}{\mathrm{X}h}$			

* Source: CAN/CSA C61000-3-06

Table 6: Voltage Distortion limits for Even Harmonics

Even Harmonics		
	Harmonic Voltage (%)	
	4-27.6kV	44kV
2	1.6	1.5
4	1	1
6	0.5	0.5
8	0.4	0.4
10	0.4	0.4
12	0.2	0.2
>12	0.2	0.2

* Source: CAN/CSA C61000-3-06

iv) Total Harmonic Distortion (THD) shall be a maximum of 3% on 44kV systems and 6.5% on other systems.

v) The DG Facility shall operate within the current harmonic limits as listed in Table 7.

Table 7: Harmonic Current Limits

Harmonic Number *h*	**5**	**7**	**11**	**13**	$\sqrt{\sum iX}$
Admissible harmonic current $i_h = I_{hi}/I_i$ (%)	5-6	3-4	1.5-3	1-2.5	6-8

* Source: CAN/CSA C61000-3-06

* I_h is the total harmonic current of order h caused by the consumer and I_i is the rms current corresponding to his agreed power (fundamental frequency)

vi) The DG Owner and/or Hydro One may be required to implement measures that will mitigate the harmonic distortions caused by the DG Facility such as by adding harmonic filters, at the DG Owner's sole expense.

vii) The limits presented in Items (iii), (iv) and (v) above exclude the harmonic distortions present on Hydro One's Distribution System when the DG Facility is disconnected from the distribution system.

viii) The TIR does not impose design limits to limit harmonic-caused telephone interference problems as it is almost impossible to predict. However, the DG Owner shall make sure that the design complies with all applicable standards and shall not cause telephone interference.

BACKGROUND INFORMATION

CAN/CSA C61000-3-06 details methods for evaluating the effects of a load or generation facility on actual network characteristics. Although the limits in stage 1 may be respected, DG Facilities must still ensure that global network effects are within the limits specified in CAN/CSA C61000-3-06.

2.2.2.5 FREQUENCY

i) The generators at the DG Facility shall operate at a nominal frequency of 60Hz.

ii) The generators at the DG Facility shall remain synchronously connected over the frequency range presented below in Table 8.

iii) The generators shall trip in the time required in accordance with Section 2.3.10 for any frequencies beyond what is presented in Table 8.

Table 8: Operating Frequency Range

Generator Size	Frequency Range (Hz)	
	Low Range	High Range
≤ 30 kW	59.3	60.5
≥ 30 kW	57.0-59.8 (adjustable set point)	60.5

* Source: IEEE 1547

2.2.2.6 POWER FACTOR

i) DG Facilities > 30 kW shall be capable of operating in constant power factors anywhere between 0.95 leading and 0.95 lagging.

ii) DG Facilities ≤ 30kW shall not be required to adjust their power factor.

iii) If warranted by local distribution system conditions (such as causing a violation of CSA/CAN3-C235-83 voltage limits at the PCC), this range may be narrower or wider and will be specified by Hydro One in the CIA.

iv) The DG Facility shall be capable of operating within lagging and leading power factor ranges with or without other DG Facilities in service on the feeder.

v) Hydro One shall determine the required operating power factor of the DG Facility during the CIA study and shall specify this to the DG Owner.

vi) Power factor correction or reactive power compensation techniques may be required.

vii) Induction generators consume reactive power and the DG Owner shall be required to provide reactive power compensation to correct the power factor at the PCC.

viii) DG Facilities greater than 10 MW (Class 4 DGs) shall be assessed by the IESO to determine whether the proposed connection is IESO-impactive[13] and whether the reactive power compensation at the generator units shall be sufficient so as not to cause any material increase in the reactive power requirements at the transmission system transformer station due to the operation of the DG Facilities at all load conditions on the feeder.

BACKGROUND INFORMATION

Hydro One shall determine the required operating power factor of the DG Facility during the CIA study and shall specify this to the DG Owner. Typically, this operating power factor will be in the range of 1.0 to 0.95 leading (importing reactive power from Hydro One's Distribution System).

2.2.2.7 LIMITATION OF DC INJECTION

i) The DC current injection by the DG Facility shall not be greater than 0.5% of the full rated output current at the PCC after a period of six cycles following the energization of Hydro One's Distribution System.

[13] IESO-impactive; The Independent Electricity System Operator (IESO) will determine whether a DG Facility impacts the bulk transmission system and whether additional reactive power compensation shall be required.

2.2.3 DISTURBANCES

i) The DG Facility shall be designed, built and maintained in accordance with all applicable codes, regulations and standards, along with the requirements of the TIR. The design shall minimize the impact of:

a) overvoltages during ground faults;

b) electric disturbances which can cause irregular power flows;

c) interference – radio, television and telephone;

d) audible noise; and

e) other disturbances which may reduce the reliability of Hydro One's distribution system.

2.2.4 RESONANCE ANALYSIS

i) The prudent design of a DG Facility should include careful consideration of resonance and ferroresonance.

ii) Ferroresonance or resonance studies are not mandatory.

iii) If resonance problems do arise, full co-operation and data sharing on the part of the DG Owner shall be required.

BACKGROUND INFORMATION

The design of the DG Facility should include a careful examination of resonance. Resonance can cause damage to Hydro One's Distribution System, electrical equipment of Hydro One's customers, and the electrical equipment at the DG Facility.

Ferro-resonance in a distribution feeder can take place, primarily, under single-phasing conditions on three-phase segments of feeders. In this case, overvoltages would last until anti-islanding, or open-phase protection removes all DG Facilities from the affected feeder.

2.2.5 SELF-EXCITATION ANALYSIS

i) DG Facilities with induction generators and not equipped with Transfer Trip (Section 2.3.13) shall conduct studies to assess whether there is a possibility of self-excitation.

ii) Self-excitation analysis, if required by Item (i) above, shall be submitted to Hydro One for review.

2.3 PROTECTION REQUIREMENTS

2.3.1 GENERAL REQUIREMENTS

i) All protective device settings and protection scheme designs must be submitted to Hydro One for review.

ii) Protections must not be interlocked with the position of any isolating/interrupting devices.

iii) Protection settings may be required to be changed over time to maintain adequate system protection as the system configuration changes.

iv) All protection operations shall ensure that the generator(s) and all HV Ground Sources are isolated from Hydro One's Distribution System within the required time from the start of the disturbance.

v) All protection designs must:

  a) ensure proper coordination with Hydro One's protections;

  b) be failsafe; and

  c) ensure that both the DG Facility and Hydro One's distribution system, customers and general public safety are maintained.

vi) The design of the protections at the DG Facility shall be performed by a qualified professional engineer to ensure that the overall protection scheme will ensure a safe and reliable interconnection to Hydro One's Distribution System.

vii) Protection relays shall be "utility grade" and shall meet the minimum requirements specified in IEEE C37.90, "Standard for Relays and Relay Systems Associated with Electrical Power Apparatus," latest edition as well as meet the requirements in Section 2.1.20 and Section 2.1.21. "Industrial grade" relays shall not be permitted for the interconnection protection.

viii) Protection functions shall remain operational after distribution system disturbances or loss of supply from the distribution system for the required period of time needed to operate properly.

ix) Communication facilities between Hydro One's TS and recloser and the DG Facility may be required as a result of DG Facility interconnections.

x) The interconnection protection is required to have a dedicated device but if the DG Owner decides to combine some of the protection functions in other relays, this would be subject to Hydro One's approval.

xi) Additional protections other than the ones listed in the TIR may be required depending on the application and shall be communicated to the DG Owner at the appropriate stage.

BACKGROUND INFORMATION

The protection schemes shall be designed to detect the conditions presented in this section of this requirements document including but not limited to:

- balanced and unbalanced faults (line to ground, line to line, three phase) at the DG Facility and Hydro One's distribution system (entire distribution feeder that DG Facility is connected to);
- abnormal frequencies;
- abnormal voltages; and
- islanding conditions.

The protection schemes employed shall coordinate with Hydro One's distribution system protections and shall be designed for current and anticipated future fault levels. Dedicated communications may be required to facilitate timely clearing of faults. In some cases, communication facilities between the TS and recloser may be required to facilitate coordinated tripping and reclosing for all of the protective devices.

Protections must not be interlocked with the position of any isolating/interrupting devices. This avoids un-necessary protection complexity that would cause reliability to be compromised.

All protection operations shall ensure that the DG Facility's generator(s) and all sources of ground current are tripped within the required time from the start of the disturbance. For DG Facilities utilizing a DGIT with Wye-Ground configuration on the high voltage side (refer to Section 2.1.12, "Interconnection Transformer Configuration"), both the DGIT and the generators must be tripped within the required clearing time (refer to Section 2.1.8).

All protection scheme proposals will need to be reviewed and accepted by Hydro One.

2.3.2 SENSITIVITY AND COORDINATION

i) The DG Facility's interconnection protection shall provide adequate sensitivity to detect abnormal conditions as required in Section 2.3 and isolate its generator(s) and if present, its HV ground source, from Hydro One's Distribution System.

ii) The design of the DG Facility's interconnection protection system shall coordinate with other Hydro One protection system devices.

2.3.3 PROTECTION OPERATING TIMES

i) The DG Facility's interconnection protection shall disconnect the DG Facility's generation and HV ground sources, if present, from Hydro One's Distribution System within the required time as specified in the individual requirements throughout the TIR.

BACKGROUND INFORMATION

Example: For any phase and ground faults: "a maximum of 500ms from inception of the fault condition and islanding conditions for DG Facilities equipped with Transfer Trip". This time is measured from the start of the abnormal condition to the time the generator will cease energizing Hydro One's distribution system. This is a maximum clearing time and in certain instances, the clearing time may be more stringent. Hydro One will determine this in the CIA.

Timing diagrams for different events are shown for reference in Appendix F.

2.3.4 BREAKER FAIL (BF)

i) DG Facilities with an aggregate output > 500kW shall provide breaker failure protection for the primary interrupting device (i.e. breaker, HVI, LVI) that is responsible for disconnecting the generator and/or the HV ground sources from Hydro One's Distribution System.

ii) The breaker failure protection should have a maximum pickup time delay of 0.3s after initiation.

iii) In the event of an HVI breaker fail condition, the breaker fail protection shall:

   a) trip the next zone at the DG Facility, specifically the upstream isolation device and all LV breakers shall be tripped; and

b) remove the prime mover and excitation system as appropriate.

iv) In the event of an LVI breaker fail condition, the breaker fail protection shall ensure that a fault in the DG Facility is cleared and will not affect the Distribution System by:

a) tripping the HVI if an HVI exists;

b) opening the motorized disconnect switch (Isolation Device) as explained in Item (vi) below if an HVI does not exist;

c) removing the prime mover and excitation system as appropriate.

v) The motorized disconnect switch (see requirements in Section 2.1.7 Item (iii)(b)) shall be opened by a separate auxiliary relay in the event of a breaker fail condition to ensure that the DG Facility is properly isolated from Hydro One's Distribution System.

vi) The motorized disconnect switch shall be used to automatically isolate the DG Facility from the distribution system. In the event that an alternate interrupting means (fuses or otherwise) is not provided by the DG Facility or if such alternate interrupting means fail to coordinate with the opening of the motorized disconnect switch, then the disconnect switch may incur significant damage when attempting to interrupt a sustained fault current condition as it is not rated for breaking fault current. The design of the DG Facility shall take this into consideration when deciding on a location for the Isolation Device to ensure that safety of the DG Facility personnel, Hydro One's personnel and general public will be ensured.

vii) In the case of a circuit switcher being used, the interrupter and the motorized disconnect shall be specifically chosen to operate independently and no additional BF protection shall be required. If the motorized disconnect switch in the circuit switcher is not rated to break load, an additional load break switch shall be required to satisfy the requirement in Section 2.1.7.

viii) The design of the BF protection for the HVI shall be submitted to Hydro One for review and acceptance.

ix) DG Facilities ≤ 500kW shall be exempted from Items (i) through (viii) above, but shall have an alternate means of disconnecting the DG Facility generation energy source from the Distribution System when the associated breaker fails to open for any interconnection protection operations. This can be achieved by the opening of the isolation device, disabling an inverter, or by removing the prime mover and excitation system as appropriate.

BACKGROUND INFORMATION

Breaker Fail protection needs to be included in the DG Facility's interconnection protection design for both the High Voltage Interrupter and Low Voltage Interrupter to ensure that a breaker/interrupter failure will not disrupt Hydro One's Distribution System and/or the DG Facility by ensuring that faults are cleared in a timely fashion. A means of automatic backup isolation is required to allow quick restoration of the distribution feeder.

DESIGN CONSIDERATION

In normal operation, when the HVI isolates the facility, the motorized disconnect switch will follow, opening a short period afterwards. It can also be designed to open sequentially – motorized disconnect opens if the HVI does not OPEN following a trip initiation.

2.3.5 SINGLE PHASE GENERATORS

i) Minimum protection requirements for single phase DG Facilities shall be in accordance with Table 9 below and are mandatory for all generators to which this TIR document is applicable.

ii) Inverter type generators shall be compliant with CSA Standards, C 22.2-107.1 "General use Power Supply" **and** CAN/CSA 22.2 No 257-06 "Interconnecting inverter based micro distributed resources to distribution system" **and** bear a certification mark recognized by the Ontario Electrical Safety Code.

iii) The final design of the protection system shall be submitted to Hydro One for approval in accordance with Section 2.3.19 of the TIR.

Table 9: Minimum Protections Required for Single Phase DG Facilities

Protection Description	IEEE Device #
Interconnect Disconnect Device	89
Generator Disconnect Device	
Over-Voltage Trip	59
Under-Voltage Trip	27
Over Frequency Trip	81O
Under Frequency Trip	81U
Overcurrent**	50/51
Distance ***	21
Synchronizing Check*	25
Anti-Islanding Protection	Refer to Section 2.3.12
Additional Protections May Be Required	

* Only required for synchronous generators and other types which have stand-alone capability

** Could be provided by magnetic circuit breaker or fuse

*** Distance may be required to be able to detect faults along the entire length of the feeder

DESIGN CONSIDERATION

Figure 11 below shows a typical protection SLD for single phase DG Facilities and is given for information purposes only. The protection system can be designed differently than shown in this figure.

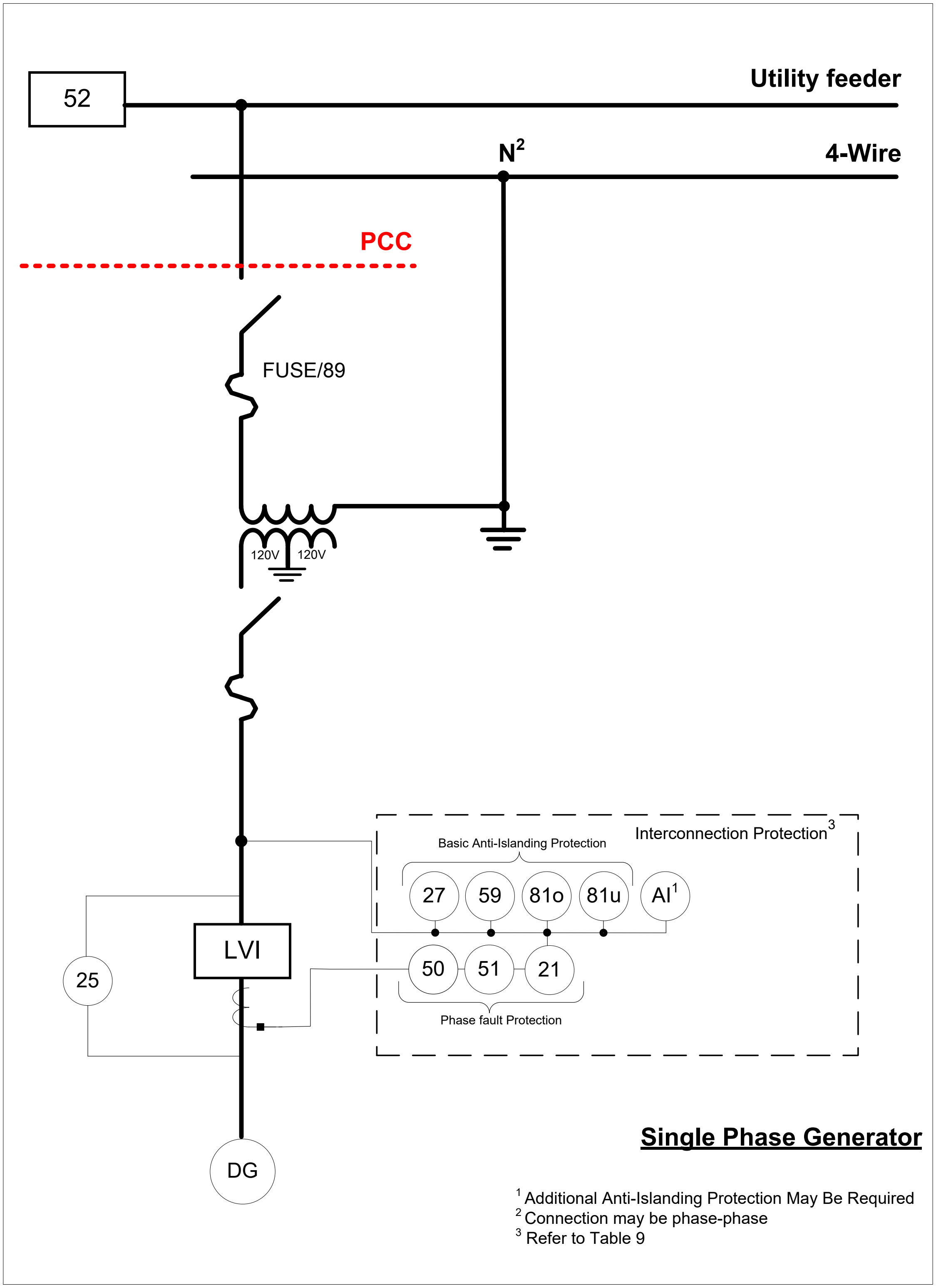


Figure 11: Typical Protection for Single Phase DG Facility Installations

2.3.6 THREE PHASE GENERATORS

i) Three Phase DG Facilities shall have the minimum protection requirements as shown below in Table 10 and are mandatory for all generators to which the TIR is applicable.

ii) Inverter type generators shall be compliant with CSA Standards, C 22.2-107.1 “General use Power Supply” **and** CAN/CSA 22.2 No 257-06 “Interconnecting inverter based micro distributed resources to distribution system” **and** bear a certification mark recognized by the Ontario Electrical Safety Code.

iii) All three-phase DG Facilities, including those using multiple three-phase inverters or multiple single-phase inverters, shall meet the following conditions:

a) be able to maintain a balanced 3-phase output under all operating conditions;

b) be able to detect the loss of voltage in one or more phases of Hydro One’s distribution system and automatically cease to energize all phases from the interconnected system; and

c) be able to detect the loss of voltage in one or more phases of the DG Facility’s electric power production source and automatically cease to energize all phases from the interconnected system.

iv) The final design of the protection system shall be submitted to Hydro One for approval in accordance with Section 2.3.19 of the TIR.

Table 10: Typical Interconnection Protections for Three Phase DG Facilities

Function Requirement	Protection Element function	Device # [14]	Synchronous	Induction	Inverter [15]	Section
Basic Anti-Islanding	Over-Voltage	59	Required	Required	Required	2.3.11, 2.3.12 iii)
	Under-Voltage	27	Required	Required	Required	
	Over-Frequency	81O	Required	Required	Required	2.3.10, 2.3.12 iii)
	Under-Frequency	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 [16]	2.3.12 iv)
	Vector Surge	78	≤ 500 kW	≤ 500 kW	Not required [16]	
	Directional Reactive Power Relay [17]	32R	≤ 500 kW [17]	≤ 500 kW [17]	Not required [16]	
Phase Fault Protection	Phase Over-current	50	Required	Required	Required	2.3.7
	Phase Inverse Timed Over-current [18]	51	See Note [18]	See Note [18]	See Note [18]	
	Voltage Controlled Over-current [18, 19]	51V	See Notes [18, 19]	See Notes [18, 19]	See Notes [18, 19]	
	Directional Phase Over-current [20]	67	Required [20]	Required [20]	Required [20]	
	Phase Distance [19, 20]	21	See Notes [19, 20]	See Notes [19, 20]	See Notes [19, 20]	
	Under-Voltage [21]	27	See Note [21]	See Note [21]	See Note [21]	
Ground Fault Protection	Neutral Over-current	50N	Required	Required	Required	
	Neutral Inverse Timed Over-current [18]	51N	See Note [18]	See Note [18]	See Note [18]	
	Directional Neutral Over-current [20]	67N	Required [20]	Required [20]	Required [20]	
	Ground Distance [19, 20]	21N	See Notes [19, 20]	See Notes [19, 20]	See Notes [19, 20]	
	Under-Voltage [21]	27	See Note [21]	See Note [21]	See Note [21]	
	Ground Overvoltage [22]	59G	Required [22]	Required [22]	Required [22]	

[14] All protection element functions must be shown on Single Line Diagrams
[15] Three-phase DG Facilities up to 500kW comprised of a single three-phase inverter unit that is CSA certified and bears a certification mark recognized by OESC shall be deemed compliant to Table 10. DG Facilities that consist of multiple three-phase inverters or multiple single-phase inverters shall comply with Section 2.3.6 of the TIR.
[16] Other passive anti-islanding protection functions may not be required if inverters have active anti-islanding controls
[17] Directional Reactive Power relay is an alternative to 78 (Vector Surge) provided that there is a predictable reverse reactive power flow for island conditions
[18] An alternative or complement to Over-current (50, 50N). Special caution is needed for selection of inverse-time characteristics that meet time constraints
[19] May be used to provide distinction between normal load and feeder-end fault conditions when basic over-current (50, 50N) is insufficient
[20] May be used to provide distinction between internal and external faults for the reconnection of DG Facility
[21] May be used to provide fault protection for DG Facilities where fault current in-feed levels are too small for practical detection by over-current or distance elements
[22] Required for DG Facilities that do not contribute ground current to ground faults on Hydro One's distribution system

Function Requirement	Protection Element function	Device # [14]	Synchronous	Induction	Inverter [15]	Section
Open Phase and Phase Unbalance	Negative Sequence Current	46	as per Section	as per Section	as per Section	2.2.2.2
	Negative Sequence Voltage	47	as per Section	as per Section	as per Section	2.3.8
Ferro-resonance	Peak detecting Overvoltage [23]	59I	See Note [23]	See Note [23]	See Note [23]	2.3.8
Synchronization	Synchronizing	25	Required	as per Section	as per Section	2.4.4

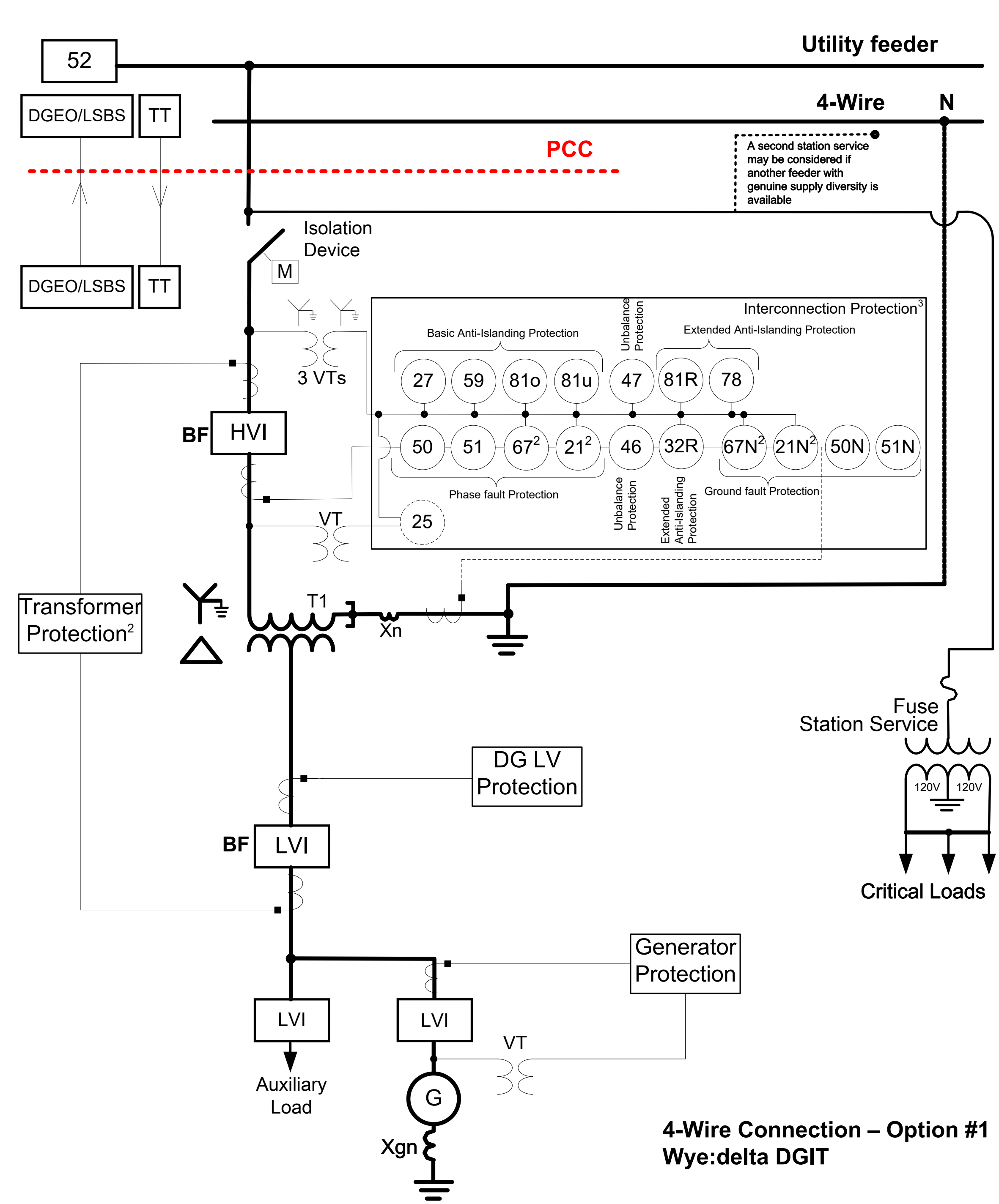
[23] May be required if DGIT connection is vulnerable to ferro-resonance e.g. open phase and HV delta connections

DESIGN CONSIDERATION

Figure 12, Figure 13, Figure 14, Figure 15, Figure 16, Figure 17, and Figure 18 shown on the next seven pages contain typical protection drawings for three-phase DG Facilities connecting to Hydro One's 4-Wire Distribution System.

Figure 19 contains a typical protection drawing for three-phase DG Facilities connecting to Hydro One's 3-Wire Distribution System.

The protection systems can be designed differently and the examples shown in the TIR are for informational purposes only. Additional protections may be required. Generator protections are not the focus of the TIR and no requirements are set by Hydro One. It is up to the DG Owner to ensure that the generators are protected sufficiently.



[2] DG protection must be capable of selectively detecting faults on the DG side of the HVI to disable auto-reclosure

[3] Refer to Table 10. Protection elements not sensitive to DGIT winding configuration may be connected to LV instrument transformer.

Figure 12: 4-Wire DGIT Option #1 Typical Protections

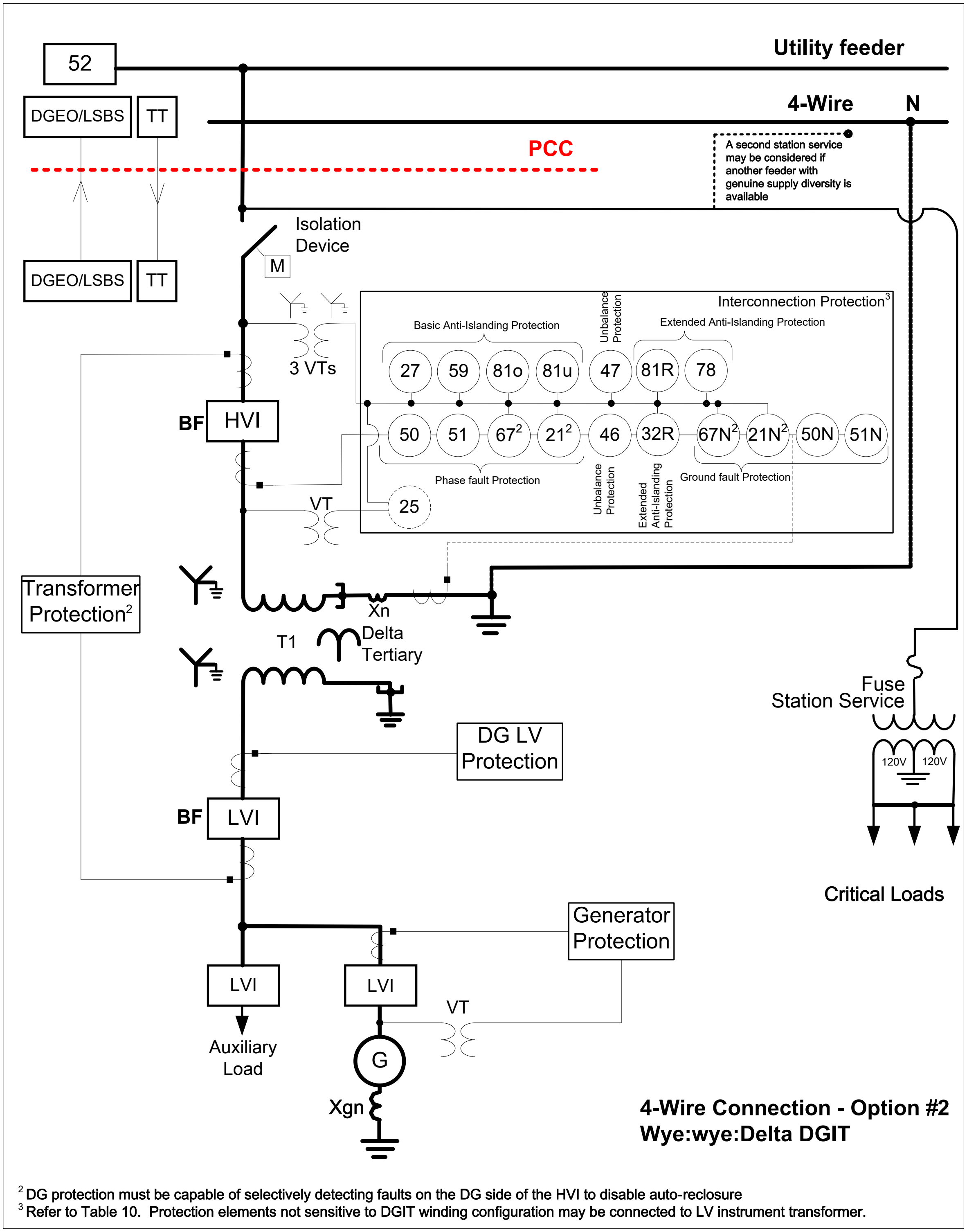


Figure 13: 4-Wire DGIT Option #2 Typical Protections

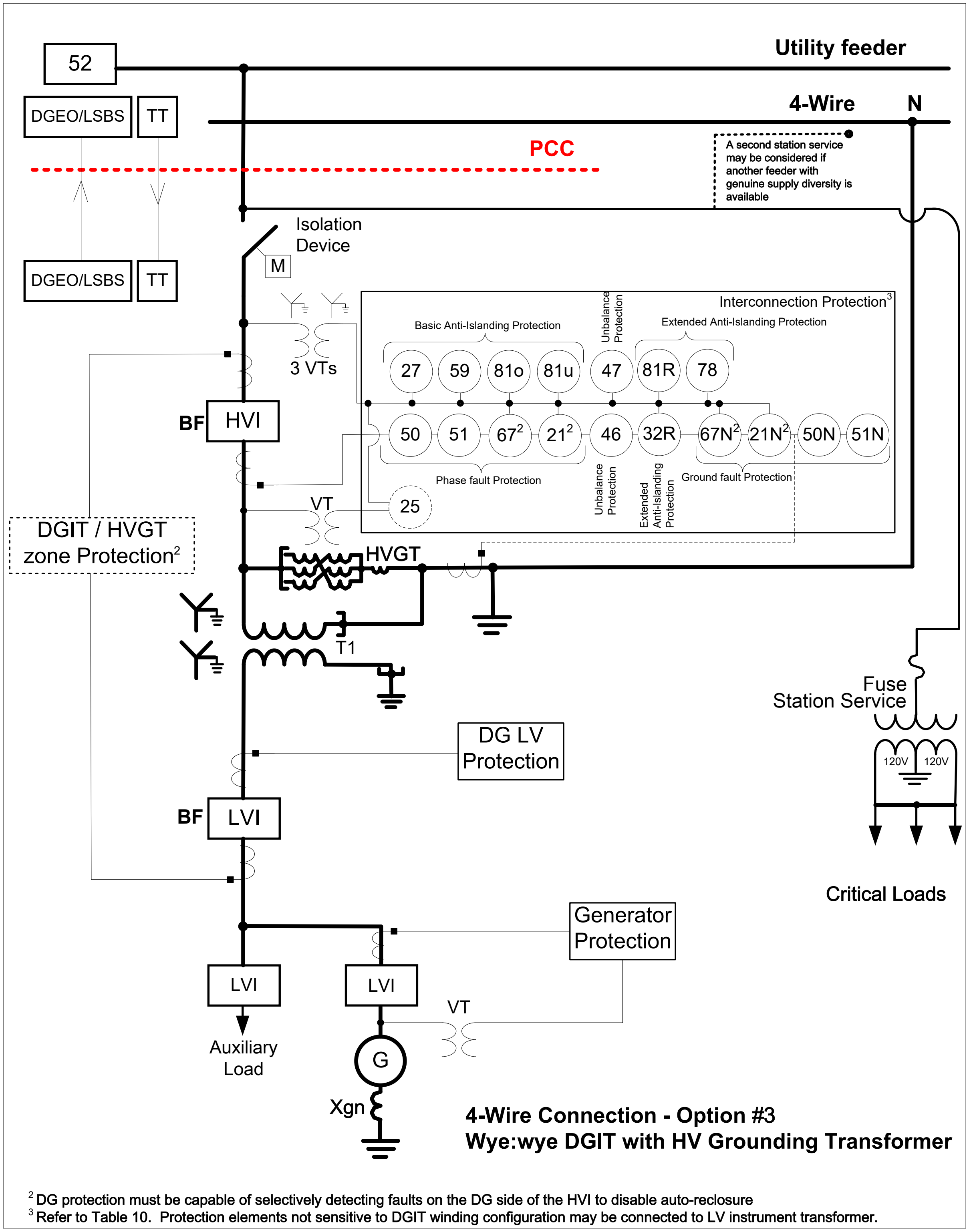
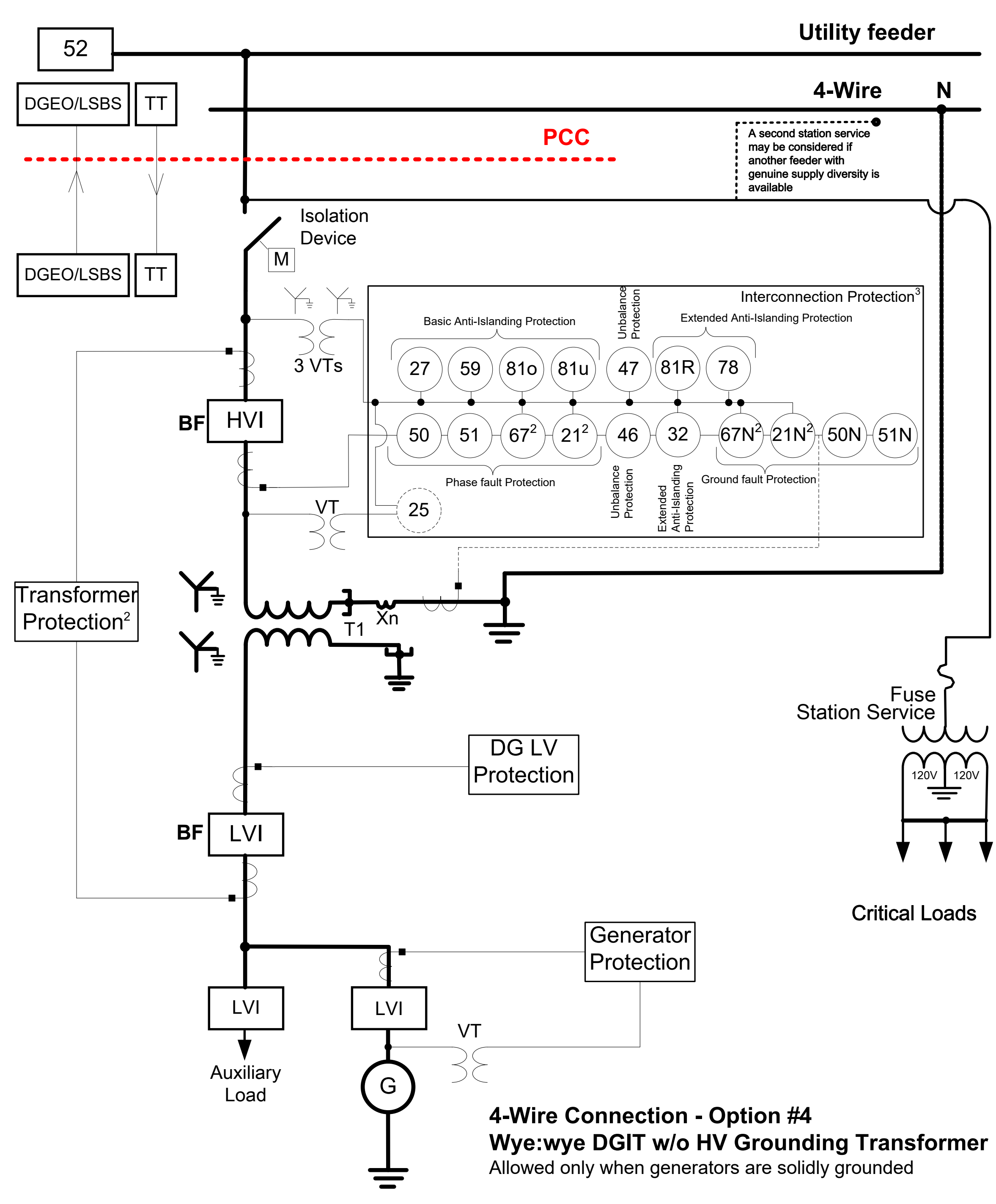


Figure 14: 4-Wire DGIT Option #3 Typical Protections



[2] DG protection must be capable of selectively detecting faults on the DG side of the HVI to disable auto-reclosure
[3] Refer to Table 10. Protection elements not sensitive to DGIT winding configuration may be connected to LV instrument transformer.

Figure 15: 4-Wire DGIT Option #4 Typical Protections

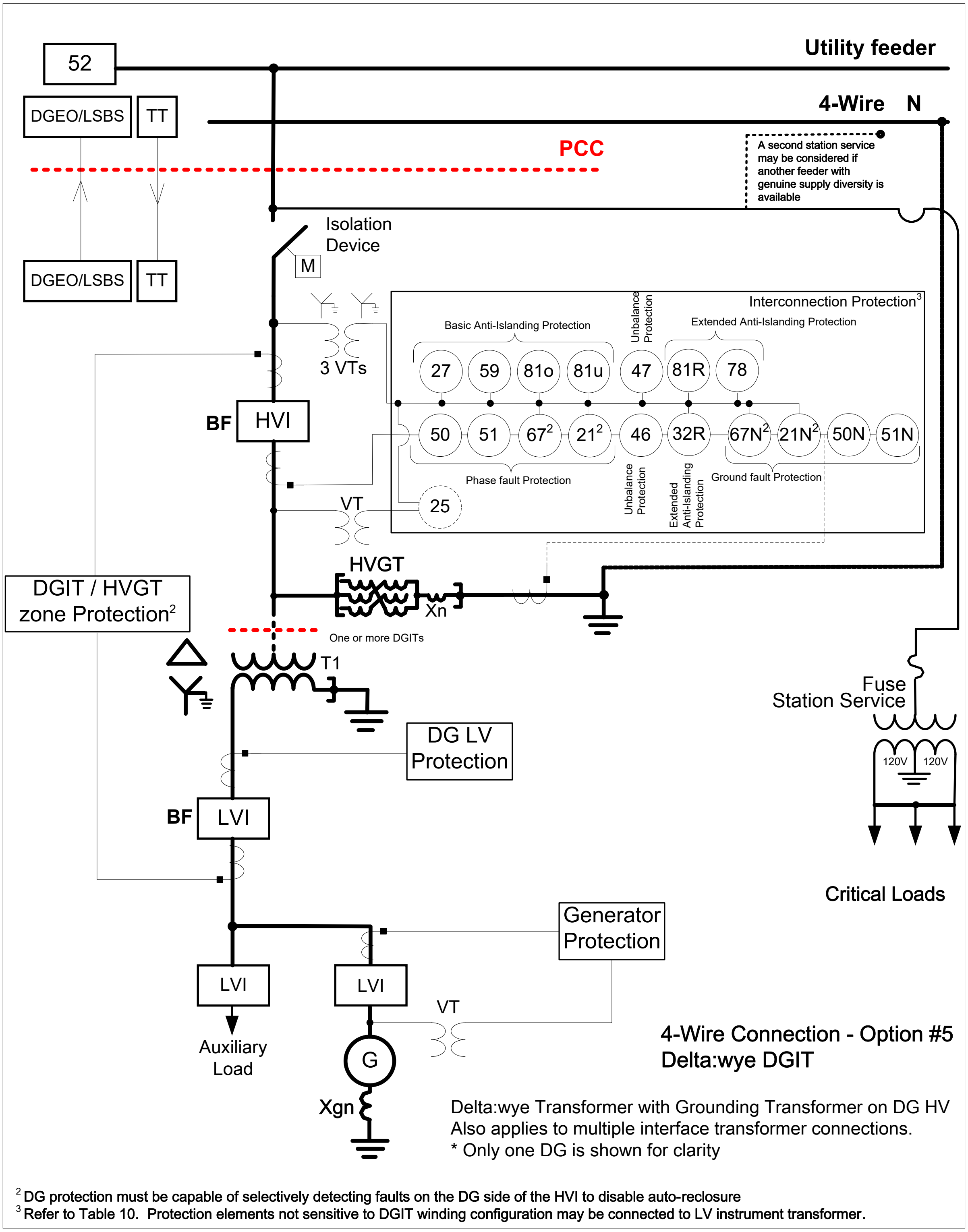
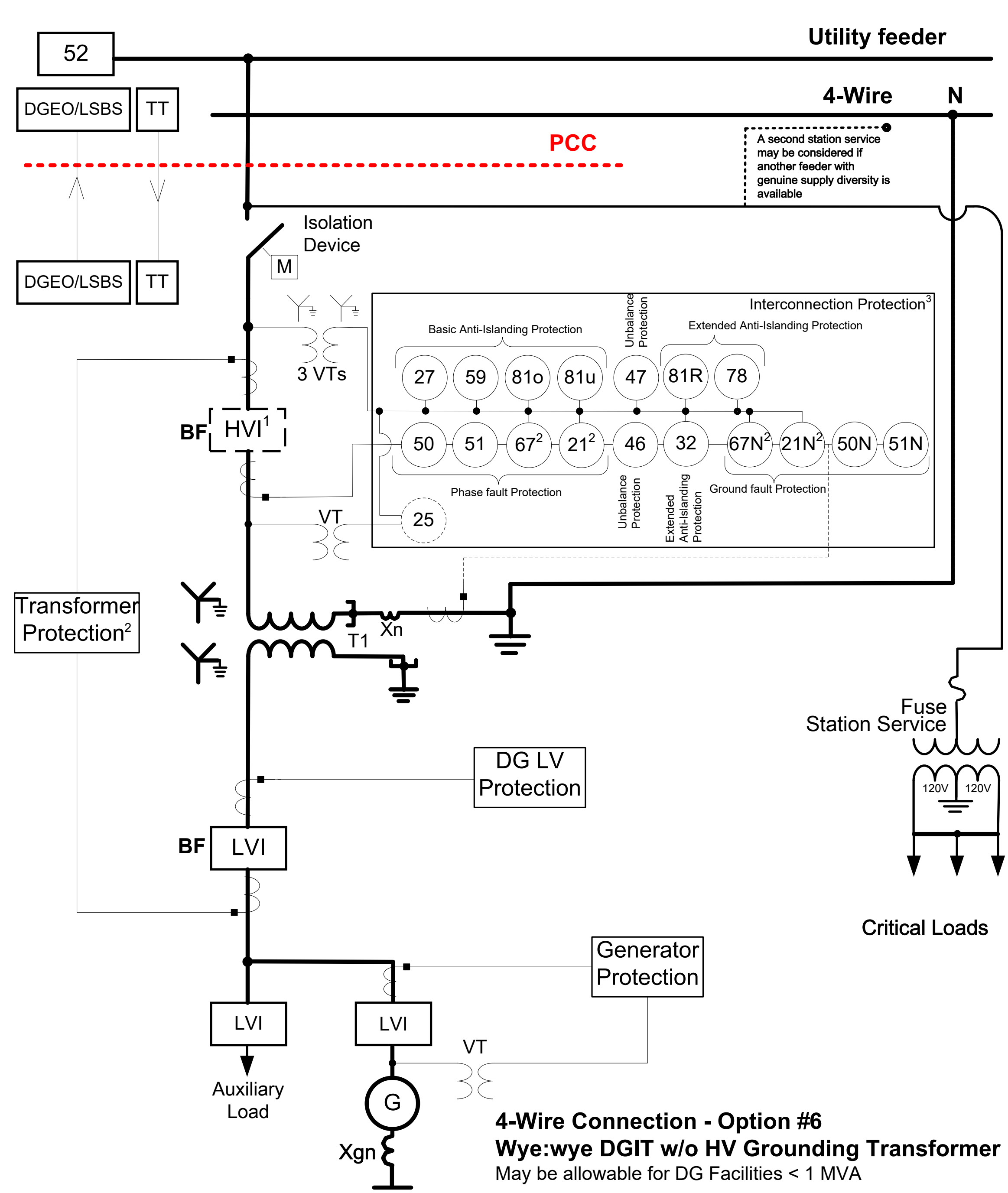
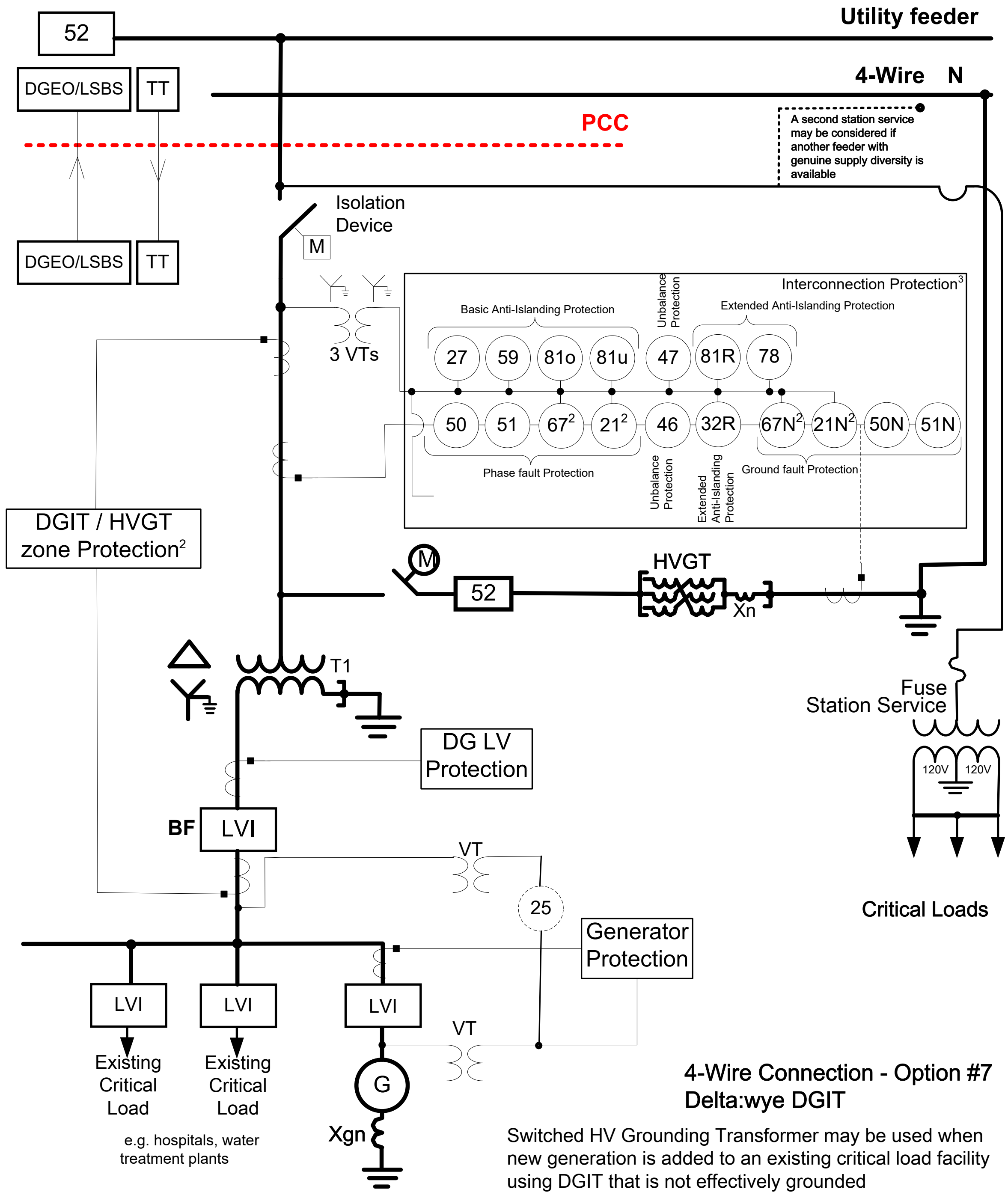


Figure 16: 4-Wire DGIT Option #5 Typical Protections



[1] DG Facility shall have an HVI or fuses to provide protection for DGIT and HV faults within the DG facility.
[2] DG protection must be capable of selectively detecting faults on the DG side of the HVI to disable auto-reclosure
[3] Refer to Table 10. Protection elements not sensitive to DGIT winding configuration may be connected to LV instrument transformer.

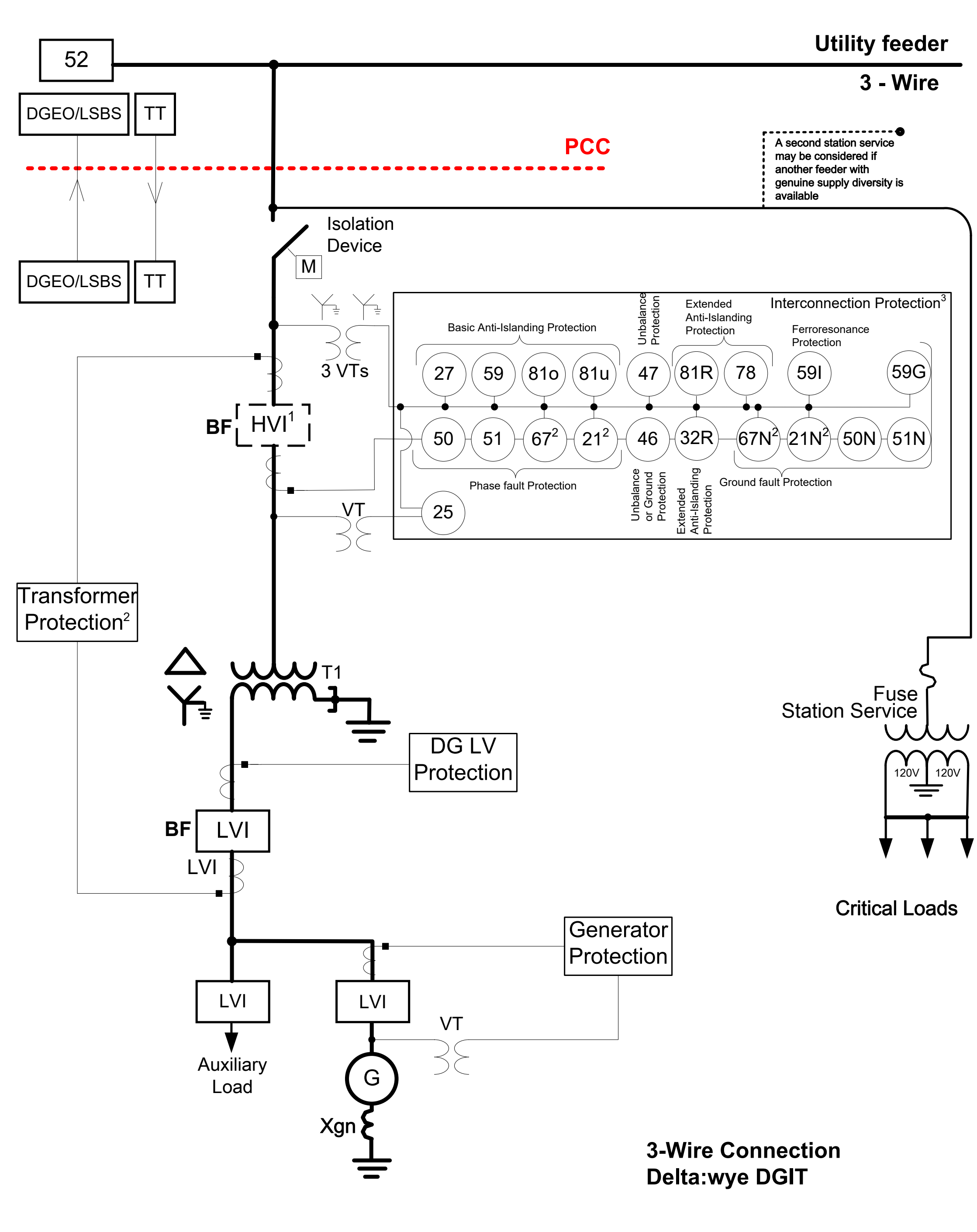
Figure 17: 4-Wire DGIT Option #6 Typical Protections



[2] DG protection must be capable of selectively detecting faults on the DG side of the HVI to disable auto-reclosure

[3] Refer to Table 10. Protection elements not sensitive to DGIT winding configuration may be connected to LV instrument transformer.

Figure 18: 4-Wire DGIT Option #7 Typical Protections



[1] DG Facility shall have an HVI or fuses to provide protection for DGIT and HV faults within the DG facility.
[2] DG protection must be capable of selectively detecting faults on the DG side of the HVI to disable auto-reclosure
[3] **Refer to Table 10.** Protection elements not sensitive to DGIT winding configuration may be connected to LV instrument transformer.

Figure 19: 3-Wire DGIT Typical Protections

2.3.7 PHASE AND GROUND FAULT PROTECTION

i) The DG Facility's interconnection protection shall ensure that the DG Facility will detect and isolate itself and any HV ground sources[24] from Hydro One's Distribution System for:

   a) All internal faults within the DG Facility; and

   b) All external faults on the interconnected feeder including single phase lateral taps[25]. This applies to all phase-phase and phase-ground faults.

ii) Phase and ground protections shall always be operational whenever phase and ground current can be sourced from the DG Facility.

iii) The protective device selectivity and sensitivity shall be maintained over the full range of minimum to maximum fault currents (present and anticipated future levels) with the DGs infeed.

iv) The DG Facility shall be capable of selectively detecting faults on the DG Facility side of the HVI, and shall disable the HVI auto-reclosure scheme – Refer to Section 2.4.7.

v) The total clearing time for faults on Hydro One's Distribution System or for faults in the DG Facility shall be no more than:

   a) 500ms for DG Facilities equipped with fast Transfer Trip; or

   b) 200ms for DG Facilities not equipped with fast Transfer Trip. This can be relaxed to 500ms if the DG Owner can demonstrate that the DG Facility fault contributions will not encroach on Hydro One's Distribution System minimum fuse melt characteristic.

   [**Note:** The total clearing time is measured from the start of the abnormal condition to the time that the DG Facility ceases to energize Hydro One's Distribution System].

BACKGROUND INFORMATION

Phase and ground protections are required to clear infeed from the DG Facility into faults on the interconnected feeder and to isolate the DG Facility from Hydro One's Distribution System when faults occur within the DG Facility.

Hydro One will provide the DG Owner the maximum phase and ground fault currents and Thevenin equivalent impedances at the PCC with existing DG Facilities connected and

[24] Refer to Section 1.8 for definition of HV Ground Source.
[25] Must see entire feeder for phase and ground faults – past reclosers/sectionalizers/fuses

without the concerned DG Facility connected in the CIA. Hydro One will also provide the DG Owner the maximum impedance faults that the DG Facility shall be capable of detecting during the design stage.

Whenever the fault infeed from the DG Facility is large enough to melt fuses, a 200ms clearing time is required for installations without Transfer Trip in order to prevent the fuses on the interconnected feeder from starting to melt. Otherwise the reliability and restoration times of Hydro One's Distribution System would be compromised. Protections must not be interlocked with the position of any isolating/interrupting devices to avoid introducing un-necessary complexity that would cause reliability to be compromised.

Consideration must be given to the possibility of DG Facility ground source currents being present when the generation is out-of-service if the HV Ground Source is not disconnected. This will depend on the HV grounding configuration (see Section 2.1.12). These ground sources must be isolated upon detection of the conditions outlined in Section 2.3.7 Item (i).

A means of automatic backup isolation is required to cater for an HVI or LVI failure condition. The automatic backup isolation is required to allow quick restoration of the distribution system feeder following an HVI or LVI failure condition. Refer to Section 2.3.4 for Breaker Fail requirements.

DESIGN CONSIDERATION

Standard over-current phase and ground elements (type 50, 51 or 67) may not be capable of detecting all faults along the entire feeder and may not coordinate with Hydro One's protection systems. Distance (21) type protections may need to be considered to provide the required protection coverage. The settings for the distance elements shall be determined by the DG Owner with the information provided by Hydro One. Another consideration could be using undervoltage (27) protection to detect feeder faults provided that the voltage at the location of DG Facility's interconnection protection drops significantly for phase or ground faults on the feeder.

It may not be feasible for the DG Facility's interconnection protection to detect all faults on the feeder prior to Hydro One disconnecting its feeder breaker or recloser because of the reduction of fault current in-feeds from the sources[26]. If DG Facility's interconnection

[26] The presence of multiple sources can cause fault current in-feeds from each source to be significantly reduced if the individual source in-feeds sum together at one or more nodes (PCCs) resulting in increased total fault current flowing over sections of the feeder. Each reduction in fault current in-feed requires the sensitivity of the protections to be increased to maintain adequate fault detection capability. Increased protection sensitivity generally decreases the load carrying capability of the sources, particularly with over-current protections. Distance protections are affected to a much lesser extent and can usually be used to preserve load carrying capability.

protections are delayed to allow Hydro One's protections to operate first, the timing requirements in Section 2.3.7 Item (v) must be respected. All protection settings must take into account the natural decay of fault contribution from DG Facility sources such as direct-connected rotating machines.

2.3.8 OPEN PHASE PROTECTION

i) The DG Facility's interconnection protection must be capable of detecting the loss of any phase to which the DG Facility is connected which occurs within the DG Facility or on the interconnected feeder.

ii) Upon the detection of the open-phase condition the DG protection shall:

   a) Disconnect the generation from the Distribution System within 500ms; and

   b) Disconnect the DGIT from the Distribution System via an HVI or an HV Motorized Disconnect Switch whenever the DGIT is three-phase with a common (shared) magnetic core.

BACKGROUND INFORMATION

Open-phase protections are required to detect open-phases condition between the Distribution System and a DG Facility to prevent uncontrolled voltages from appearing on the conductors isolated from the Hydro One source of supply. The probability of open-phase conditions is highest when the DG Facility is installed on a section of Hydro One's distribution system that utilizes single phase tripping.

Uncontrolled Voltage from Generation

Any connected DG Facility's generation will directly energize the phase conductor that is islanded from the Hydro One source, but the voltage will not be regulated and can be expected to deviate outside of acceptable limits.

Uncontrolled Voltage from DGIT Back-Feed

If the DG Facility's generation is not connected, the open-phase conductor can be back-energized from the remaining connected phases via the three-phase shared-core DGIT. This back-feed produces abnormal voltages (high or low). In some cases extreme over-voltages associated with ferroresonance can occur if the DGIT is ungrounded and there is significant phase-ground capacitance on the open phase circuit.

In both cases the voltage on the open-phase Distribution System conductors will pose a safety hazard to maintenance personnel and will not be maintained within acceptable limits.

Open-phase protections may also be used for a single-phase DG Facility to detect islanding condition.

In all cases the generators must be isolated from Hydro One's distribution system within 500ms to prevent the phase from remaining energized during recloser operations.

DESIGN CONSIDERATION

The system over and under-voltage protection elements required in Section 2.3.11 may be capable of detecting most open-phase conditions if the elements are connected phase-ground. However these voltage elements may not be sensitive enough to detect certain types of open-phase conditions when generation is connected or when there is back-feed via a three-phase shared-core DGIT. Alternate detection schemes such as phase-ground connected voltage elements, negative-sequence or negative/zero-sequence current or negative/zero-sequence voltage detection schemes may be required to provide adequate sensitivity.

2.3.9 FEEDER RELAY DIRECTIONING

i) Hydro One feeder relay phase and ground over-current elements may need to be directioned.

ii) Inline reclosers on the feeder upstream of the DG Facility may need to be directioned.

iii) The need for Items (i) and (ii) above shall be specified in the CIA for the proposed DG Facility connection.

BACKGROUND INFORMATION

Non-directional over-current protections provide adequate protection for the clearance of downstream phase and ground faults for a radial (single source) distribution system feeders. These simple over-current protections include non-directional feeder relay over-current elements, inline reclosers and fuses.

Connection of DG Facilities provides additional sources of fault current that can cause non-directional over-current protections to operate for reverse faults, upstream of the protected zone[27]. For these non-radial situations, directioning of the protections will be required to prevent operation for the reverse faults.

Distance relays are inherently directional and can be used to avoid this problem.

27 Mis-operation will occur if the aggregate DG Facility fault in-feed exceeds the operational setting of the over-current protection.

2.3.10 OVER FREQUENCY/UNDER FREQUENCY PROTECTION

i) The DG Facility's interconnection protection scheme shall have the capability of detecting abnormal frequencies shown below in Table 11.

ii) The DG Facility shall disconnect from Hydro One's Distribution System in the clearing times specified in Table 11.

iii) The clearing time in Table 11 shall be measured from the start of the abnormal condition until the time that the DG Facility ceases to energize Hydro One's Distribution System.

iv) More stringent clearing times may be specified in the CIA if required.

v) DG Facilities > 30kW shall have the frequency set point field adjustable.

vi) DG Facilities ≤ 30kW shall have the frequency set point either fixed or field adjustable.

vii) DG Facilities ≥ 1MW shall have the lower frequency set points set to comply with the NorthEast Power Coordinating Council (NPCC) "Directory D12", as shown below in Figure 20.

viii) DG Facilities > 10MW shall follow the frequency set points and clearing times specified by the IESO's SIA.

Table 11: Over/Under Frequency Protection Set Points and Clearing Times

Generator Size	Frequency Range (Hz)	Clearing Times(s)*
≤ 30 kW	> 60.5	0.16
	< 59.3	0.16
> 30 kW	> 60.5	0.16
	< (59.8 – 57.0) - adjustable	Adjustable 0.166 to 300
	< 57.0	0.16

* Generators ≤ 30kW – Maximum clearing time

* Generators > 30kW – Default clearing time

Source: IEEE 1547

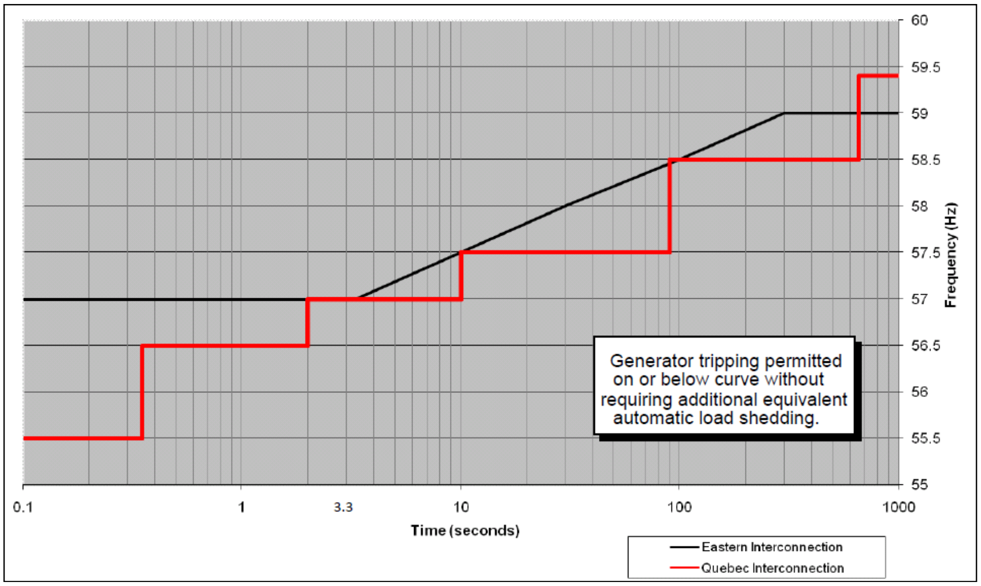


Figure 20: NPCC Directory D12 Generator Underfrequency Setting Requirement

2.3.11 OVERVOLTAGE/UNDERVOLTAGE PROTECTION

i) The DG Facility's interconnection protection scheme shall have the capability of detecting abnormal voltages shown in Table 12.

ii) The DG Facility shall disconnect from Hydro One's Distribution System in the clearing times specified in Table 12.

iii) Voltage shall be measured:

a) phase-neutral for single phase installations;

b) phase-neutral for grounded Wye-Wye transformer configurations; or

c) phase-phase for all other installations.

iv) The voltages shall be detected at the PCC.

v) If the requirement in Item (iv) above is not practical or feasible, estimated values may be used if approved by Hydro One.

vi) The clearing time in Table 12 shall be measured from the start of the abnormal condition until the time that the DG Facility ceases to energize Hydro One's Distribution System.

vii) More stringent clearing times may be specified in the CIA if required.

viii) DG Facilities > 30kW shall have the voltage set point field adjustable.

ix) DG Facilities ≤ 30kW shall have the voltage set point either fixed or field adjustable.

x) Undervoltage relays should be time-delayed to avoid unnecessary tripping while over-voltage relays may be instantaneous.

xi) High speed instantaneous voltage protection may be considered for detecting ferroresonance and self-excitation conditions.

xii) DG Facilities > 10MW shall follow the voltage set points and clearing times specified by the IESO's SIA.

Table 12: Over/Under Voltage Protection Setting and Clearing Time

Voltage Range (% of base voltage)	Clearing Time(s)*
V < 50	0.16
50 ≤ V < 88	2.00
110 < V < 120	1.00
V ≥ 120	0.16

* DG ≤ 30 kW – Maximum clearing time
* DG > 30 kW – Normal clearing time

Source: IEEE 1547

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 protection 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 an interim protection until Hydro One standardizes on a Transfer Trip solution for DG Facilities ≤ 500kW[28]:

a) Rate of Change of Frequency (ROCOF); and

b) Vector Surge or Reverse Reactive Power.

v) The passive anti-islanding protection scheme in Item (iv) above shall be submitted to Hydro One for approval.

vi) The passive anti-islanding protections in Item (iv) above shall be set as sensitive as possible to reduce the non-detection zone and can be changed in the future if it is found to cause unjustified nuisance trips. These settings changes shall have to be pre-approved by Hydro One prior to implementation.

vii) If Hydro One does not find a suitable standardized solution to Transfer Trip for DG Facilities ≤ 500kW, the interim passive anti-islanding protections in Item (iv) above shall be changed out to Transfer Trip as referred in Section 2.3.13.

viii) The DG Owner shall be aware and accept the consequences of utilizing passive anti-islanding schemes in Item (iv) above as a primary anti-islanding protection and shall not hold Hydro One responsible for any damage incurred due to islanded operation from events such as out-of-phase reclosing.

ix) DG Facilities ≤ 500kW shall have provision for the capability to receive Hydro One trip signals and cease generation; i.e., shall have provision for the installation of equipment required to accommodate standardized Transfer Trip solution for DG Facilities ≤ 500kW. The actual implementation is not required but may be requested by Hydro One at a later date to be implemented at the DG Owner's cost within 90 days.

BACKGROUND INFORMATION

An electric island is a section of the distribution system which, when disconnected from the rest of the Hydro One system, remains energized by 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 quality problems;
- prevent out-of-phase reclosing between Hydro One's distribution system and the DG Facility;

[28] Hydro One is currently testing ENERPULSAR technology to be used as a low cost Transfer Trip Solution.

- reduce the risks of safety hazards caused by islanding; and
- add redundancy to other protections.

Anti-islanding protection may involve different protection functions. Each DG Facility connected to Hydro One's system shall contain this protection and must demonstrate that the DG Facility will not sustain an island longer than permitted. In certain installations, the installation of dedicated communications (transfer trip) and protection schemes may be required for anti-islanding protection and is discussed in Section 2.3.13. Appendix D has detailed information on Anti-Islanding Protection and discusses the different requirements for Transfer Trip. Please refer to this appendix for more information. Induction generators, due to the possibility of self-excitation, also have this requirement.

To facilitate the connection of DG Facilities 500kW and less, passive Anti-Islanding protections, specifically Rate of Change of Frequency and Vector Surge or Reverse Reactive Power, may be considered as an interim solution until other effective low-cost alternate solutions are available and approved (i.e. ENERPULSAR pilot projects currently underway – pulse based anti-islanding protection). These special considerations for DG Facilities less than 500kW have been made to enable these generators to connect with the associated risks of passive anti-islanding technologies without having to wait for an approved standardized solution.

DG owners that decide to connect without TT must understand the risks and shall accept the liabilities associated with adverse impacts caused by prolonged islanding of their generation for greater than 500ms.

The DG Facility, instead of using transfer trip for anti-islanding protection may use an approved Hydro One Anti-Islanding Protection Scheme. At present, there are tests being conducted and if and when any of these schemes are approved by Hydro One to meet anti-islanding protection requirements, they will be posted in this section in a future revision.

2.3.13 TRANSFER TRIP

i) A Transfer Trip (TT) signal from the station feeder breaker(s) to the DG Facility shall be required for all DG Facilities whose aggregate capacity is 1 MW or larger.

ii) A Transfer Trip (TT) signal **from** the feeder breaker(s) and/or upstream recloser(s) (where the recloser is located between the DG Facility and feeder breaker) **to** the DG Facility shall be required for any or all of the following conditions[29]:

a) When the aggregate DG Facility capacity is greater than 50% of the minimum feeder load or the minimum load downstream of recloser(s); or

b) When the aggregate generation, comprising of existing generation, other earlier proposed DG Facilities, and the concerned DG Facility is greater than 50% of the minimum feeder load or minimum load downstream of the recloser; or

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

iii) A Transfer Trip (TT) signal **from** upstream feeder breaker(s) and/or recloser(s) **to** the DG Facility connected at downstream of Distribution Station (DS) supplied by that feeder shall be required. This is required when the aggregate generation comprising of existing generation, other earlier proposed DG Facilities, at the feeder or at the DS including concerned DG Facility is greater than 50% of minimum feeder load or the minimum load downstream of recloser respectively.

iv) A Transfer Trip (TT) signal **from** transmission line terminal breaker(s) of an upstream Transformer Station (TS) **to** the DG Facility shall also be required if the TS where the DG Facility is being proposed is radially supplied by that transmission line and there is a possibility of islanding of the entire transmission line, or where Wide area islands could exist – aggregate generation on transmission line is greater than 50% of the minimum load on the transmission line. This signal will be cascaded onto the TT signal that will be required between the TS feeder breaker and the DG Facility in Item (ii) above.

v) The DG Facility's shall cease to energize Hydro One's Distribution System with no intentional time delay and isolate all generation and HV ground sources upon receipt of a Transfer Trip signal.

vi) Transfer Trip communications shall meet the timing requirements in Table 13. The maximum TT time shall depend on the operational speed of the DG Facilities interrupting device.

29 Appendix D contains information on different possible islanding conditions and discusses when and where TT needs to be sent.

Table 13: TT Timing Requirements

Maximum TT Communication Time (ms)	Speed of DG Facility`s Interrupting Device (cycles)
83	3
67	4
50	5
33	6
17	7

vii) The DG Facility shall remain disconnected from Hydro One's Distribution System if the Transfer Trip (TT) channel is unavailable.

viii) The Transfer Trip (TT) teleprotection system shall be failsafe.

ix) Upon loss of the Transfer Trip (TT) communication channel, the generation and HV ground sources shall disconnect within 5 seconds of the channel failing. A controlled shutdown may be allowed and must be submitted to Hydro One for approval.

x) The DG Facility shall remain disconnected until the Transfer Trip (TT) channel is repaired and the controlling authority has been advised that all DG Facility interconnection protections have been restored to service.

xi) DG Facilities with an aggregate capacity of 500kW and less, may be exempted from Items (ii) and (iii) above and permitted to use passive anti-islanding protections in accordance with Section 2.3.12 Item (iv).

2.3.14 DISTRIBUTED GENERATOR END OPEN (DGEO)

i) A Distributed Generator End Open (DGEO) real-time signal from the DG Facility to Hydro One is required whenever Transfer Trip is required, as outlined in Section 2.3.13.

ii) The DGEO and LSBS (Refer to Section 2.3.15) signals shall be combined into one composite communications channel signal as outlined in the DGEO and LSBS Design Requirement in Section 2.3.16.

iii) Upon failure of the DGEO channel, Hydro One may block its feeder reclosing until the channel is repaired.

iv) The DG Owner shall make repairs in the event of channel failure as quickly as possible.

v) In the event of Item (iii) above, Hydro One can seal in Transfer Trip to the affected DG Facility until the channel is repaired to enable automatic reclosing on its feeders.

BACKGROUND INFORMATION

Distributed Generator End Open (DGEO) is a real-time signal that is continuously sent from the DG Facility to the Hydro One supply source breaker or recloser. It establishes the connection status of the generation equipment. Hydro One will utilize this signal for auto-reclose supervision of the TS feeder breaker or any upstream protective device. This will ensure that out-of-phase reclosing of the DG Facility does not occur.

2.3.15 LOW SET BLOCK SIGNAL (LSBS)

i) A Low Set Block Signal (LSBS) from the DG Facility to the Hydro One supply source breaker or recloser is required whenever Transfer Trip is required as outlined in Section 2.3.13.

ii) The LSBS and DGEO (Refer to Section 2.3.14) signals shall be combined into one composite communications channel signal as outlined in the DGEO and LSBS Design Requirement in Section 2.3.16.

BACKGROUND INFORMATION

A Low Set Block Signal (LSBS) is a transient signal that is sent from the DG Facility to the Hydro One supply source breaker or recloser, whenever a large DGIT is being energized. Detection of this signal transition at the Hydro One supply source breaker or recloser location will cause the most sensitive low-set (fuse-saving) protection to be temporarily blocked. This will prevent tripping of the Hydro One supply source during the period when there is large energizing inrush current due to the DGIT. Refer to Appendix E for more information regarding the LSBS signal.

2.3.16 DGEO AND LSBS DESIGN

i) The DGEO and LSBS (Refer to Section 2.3.14 and Section 2.3.15 respectively) signals shall be combined into one composite communications channel signal.

ii) This dual function signal shall be set to ‘1’ when the breaker is open and set to ‘0’ 1s **prior** to the energization of the DGITs.

BACKGROUND INFORMATION

The DGEO signal must be derived from the logical combination of all breakers/circuit switchers at the DG Facility interconnection between the DG Facility and the PCC necessary to establish connectivity of the DG Facility. DGEO is required at the Hydro One connection location to block closing of the breaker while the DG Facility is connected. DGEO may also be required to be sent as real-time-operating data to the OGCC, so the controlling authorities of the distribution system are aware of the connection status (as per Section 2.5). The momentary LSBS signal will always be sent just prior to reconnection, (near the end of the DGEO open condition).

"Design Considerations" and timing information can be found in Appendix E.

2.3.17 SPECIAL INTERCONNECTION PROTECTION

i) Other protections not specified in this requirements document may be required depending on the application.

ii) The DG Owner shall be aware of site specific conditions and the nature of Hydro One's Distribution System to properly assess the need for additional protections.

2.3.18 PROTECTION SCHEME FAILURES

i) The DG Facility generation and HV ground sources shall be disconnected from Hydro One's Distribution System and notify Hydro One's system operators if:

  a) The DG Facility's local interconnection protection system fails[30];

  b) The breaker trip coil or interrupting device fails;

  c) The DC supply is lost; or

  d) The TT signal channel fails.

ii) Alarm Telemetry shall be provided to Hydro One directly from the DG Facility as required in Section 2.5.

iii) With the exception of Item (i)(d) above, disconnection shall be automatic and immediate (no intentional time delay).

iv) Disconnection following TT signal failure shall be automatic but can be delayed as outlined in Section 2.3.13 Item (ix).

[30] Interconnection protection systems provided by IEDs shall have self-diagnostic (control healthy) features that detect internal relay failures

v) Hydro One may send TT to the DG Facility following a DGEO signal failure as outlined in Section 2.3.14 Item (v).

vi) The device(s) used to disconnect the generation shall remain open until such a time when the affected system is returned to normal service condition and the DG Facility is safe for reconnection to Hydro One's distribution system.

vii) The interconnection protection design submitted to Hydro One during the implementation phase of the Connection Process shall provide sufficient detail to ensure that the protection scheme failure requirements outlined in Item (i) above are addressed.

viii) In designs where self-diagnostic features do not trip the appropriate breakers upon failure, sufficient backup and/or redundancy protections shall be provided.

ix) If electro-mechanical relays are used, the protection and control design shall be of a fail-safe nature to ensure the integrity of the protection scheme under malfunctioning conditions.

2.3.19 INTERCONNECTION PROTECTION ACCEPTANCE

i) The DG Owner shall provide Hydro One with complete documentation on the proposed DG Facility's interconnection protection scheme to ensure compliance with the requirements of the TIR and all applicable standards. Documentation shall include, but is not limited to:

a) a detailed Single Line Diagram;

b) an overall description on how the protection will function;

c) a description on failure modes;

d) detailed engineering drawings that includes design details on protection and control, teleprotection and telemetering schemes and components including manufacturer and model #;

e) the protection element settings (pickup, timers, etc.);

f) details on monitoring for the protection system performance (DFR, SER, and telemetry);

g) details on backup supply to any critical loads;

h) details on the Breaker Failure protection if required by Section 2.3.4; and

  i) details on the disconnecting and interrupting device.

ii) If Hydro One proposes any changes from the review in Item (i) above, the DG Owner shall revise and re-submit the protection information to Hydro One.

iii) All documentation must be submitted together.

iv) The latest submissions will be filed by Hydro One and MUST MATCH the documentation retained by the DG Owner.

2.3.20 PROTECTION CHANGES

i) The DG Owner shall obtain Hydro One's prior written approval of all:

  a) interconnection equipment replacements;

  b) design modifications; and

  c) setting changes.

ii) Any changes without prior approval shall be deemed a violation of Distribution Connection Agreement (DCA) and may result in immediate disconnection from Hydro One's Distribution System.

2.4 OPERATING REQUIREMENTS

2.4.1 GENERAL

i) Switching that involves manual operation of air break switches shall require all connected DG Facilities to disconnect their generation from the system as directed by the Controlling Authority.

ii) In the event that the source configuration changes, other than what was studied in the DG Owner's CIA or listed in their DCA, all connected DG Facilities shall disconnect their generation from the distribution system as directed by the Controlling Authority. It shall be the DG Owner's responsibility to ensure that their protections are capable of detecting all external faults.

iii) Any temporary feeder parallels shall require that all connected DG Facilities to come off-line as directed by the OGCC.

iv) Transfer Trip and DGEO communications shall be required for DG Facilities that are 1 MW and larger connecting to Hydro One's Distribution System at voltages less than 50 kV.

v) For feeders with multiple feeder reclosers, 50% minimum feeder load calculations shall identify remaining loading levels with reclosers in open position.

vi) The DG Facility shall parallel with Hydro One's Distribution System without causing a voltage fluctuation at the PCC greater than ± 4% of the prevailing voltage level of the distribution system at the PCC and meet the flicker requirements in Section 2.2.2.3.

vii) The DG Facility (synchronous and permanent magnet generators) shall remain in synchronism with Hydro One's Distribution System while operating in parallel to Hydro One's Distribution System. The DG Facility is expected to have loss-of-field protection as part of the generator protection to quickly disconnect the generator should the excitation to the generator fail.

viii) No automatic reconnection to the system shall be allowed unless:

  a) there is always contact with the DG Owner or DG Facility operator who has the ability to immediately disconnect the DG Facility from the system if requested by the Controlling Authority (24 hours/7 days per week); or

  b) the Distributor's Controlling Authority has the ability to remotely disconnect the DG Facility from the system, and

c) feeder relay studies must be updated if circuit configuration is materially altered. If the source changes from the configuration studied in the CIA, the generator will not be allowed to reconnect.

ix) Automatic Reconnection to Hydro One's distribution system shall be locked out once voltage and frequency are not within operating ranges for a period of 15 minutes on any phase for any DG Facilities limited to one connection path if stipulated in their DCA.

x) Legacy DG Facilities need to meet the operating requirements of the TIR.

2.4.2 ISLANDING

i) Intentional islanding is not allowed at this time.

ii) Islanding detection and protection is required as per Section 2.3.12.

2.4.3 UNINTENTIONAL ENERGIZATION

i) The DG Facility shall not energize Hydro One's Distribution System when the distribution system is de-energized.

2.4.4 SYNCHRONIZATION

i) Any DG Facility that is capable of generating its own voltage while disconnected from Hydro One's Distribution System shall require proper synchronization facilities before connection is permitted.

ii) Interconnection shall be prevented if the DG Facility and Hydro One's Distribution System are operating outside the limits specified in Item (iii) below.

iii) Synchronous generators, self-excited induction generators or inverter-based generators that produce fundamental voltage before the paralleling device is closed shall only parallel with Hydro One's Distribution System when the frequency, voltage, and phase angle differences are within the ranges given below in Table 14 at the moment of synchronization.

Table 14: Resynchronization Requirements

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

* Source: IEEE 1547

iv) For synchronous generators, an approved automatic synchronization device shall be required if the plant is unattended (IEEE device number 25) to ensure that the DG Facility will not connect to an energized feeder out of synchronism.

v) Induction generators and inverter-based generators that do not produce fundamental voltage before the paralleling device is closed, and double-fed generators whose excitation is precisely controlled by power electronics to produce a voltage with magnitude, phase angle, and frequency that match those of the distribution system may not require synchronization facilities.

vi) Any proposed synchronizing scheme shall be submitted to Hydro One prior to installation and shall be able to accommodate automatic reclosing on Hydro One's distribution facilities.

2.4.5 SINGLE CONNECTION PATH

i) The requirements in Items (ii), (iii) and (v) below shall apply to DG Facility connections which have a restriction to only a single connection path (normal configuration) as stipulated in their DCA.

ii) DG Facility generation connection shall be restricted only to the "normal Distribution System supply configuration"[31] and when all required protection and control systems required for safe and reliable connection to the Distribution System are operational.

iii) DG Facility generation connection shall be restricted only to Transmission System supply configurations that have adequate minimum load connected or have adequate TT facilities in-service to prevent a Wide-Area DG island.

[31] The "normal Distribution System supply configuration" is considered to be when the feeder is supplied from one TS feeder breaker (the normal supply breaker) or DS recloser and all normally open line switches are open, as defined by Hydro One's operating diagrams.

iv) Upon request the DG Facility connection can be approved for “Alternate Grid Connection Path” if deemed acceptable by Hydro One. An additional assessment on Transmission System supply configurations shall be required.

v) The CIA and DCA shall clearly identify the Distribution System and Transmission System supply configuration(s) studied and determined to be acceptable for safe and reliable DG Facility connection in accordance with Items (i) and (iii) above.

vi) If an alternate configuration exists and if Items (ii) and (iii) above apply to the DG Facility, then the DG Facility shall be disconnected until the normal configuration is restored.

BACKGROUND INFORMATION

Alternate (abnormal) supply configurations may be required from time-to-time to circumvent planned or unplanned contingency situations (equipment failures, maintenance, upgrading and repairs) for the purpose of maintaining or restoring an adequate supply to load customers. DG Facility connections to alternate supply configurations would cause changes to short circuit levels, circuit loading, steady-state voltage profiles, transient overvoltages, protection coordination and DG island configurations.

DG Facility generation, if stipulated in their DCA, must be disconnected during alternate supply configurations unless specific provisions have been made by the CIA and implementation stages of the connection to assure the DG Facility can safely and reliably remain connected for the specific alternate connection according to all of the Technical Requirements outlined in the TIR.

Although other supply configurations may be of concern, the expected most common alternate Distribution System supply configurations that may not facilitate DG connection are as follows:

- Back-up supply of load customers from the adjacent TS feeder breaker (TS feeder tie switch closed);
- Back-up supply of load customers from another TS; or
- Extending supply to load customers connected to an isolated section of an adjacent feeder normally supplied from another source by closing a normally-open feeder-end switch.

The expected most common alternate Transmission System supply configurations that may not facilitate DG connection are as follows:

- Transfer of a TS or DS that is supplied from a single 115kV or 230kV circuit to another main terminal station that does not have adequate minimum load connected or does not have adequate TT facilities in place to prevent Wide-Area DG islands.

Different conditions need to be met before reconnecting to Hydro One's system, depending if the outage is a momentary outage or sustained outage or shutdown. They are explained in Section 2.4.7 and Section 2.4.8. Automatic Reconnection of the DG Facility to Hydro One's system is subject to specific requirements which can be found in Sections 2.4.1, 2.4.7 and 2.4.8.

2.4.6 AUTOMATIC DISCONNECTION OF GENERATION AND HV GROUND SOURCES

i) All DG Facility generation and sources of ground current shall be automatically disconnected from the Distribution System whenever the DG Facility's interconnection protection or TT operates, as required by the other sections in the TIR. The timing requirements for automatic disconnection are detailed below in Items (ii), (iii), (v), (vi) and (vii).

ii) For those DG Facilities that require TT, all generation shall be disconnected immediately (without any intentional delay) upon the receipt of a TT signal from Hydro One.

iii) For those DG Facilities that require TT, all generation shall be disconnected within 500ms of when external faults are detected on the Distribution System by the DG Facility's interconnection protection.

iv) For those self-clearing DG Facilities that do not require TT, all generation shall be disconnected within 200ms of the start of the abnormal condition on the Distribution System by the DG Facility's interconnection protection.

v) All sources of DG Facility generation shall be disconnected within 500ms when the DG Facility Anti-islanding Protection operates.

vi) All three-phase DG Facility ground sources shall be disconnected within 500ms if any of the items (ii) to (v) above operates.[32]

vii) A back-up means shall be provided for disconnecting the DG Facility generation and all grounded DGIT or HV grounding transformers that provide a ground return path for ground faults on the HV side of the DGIT, should the interrupting device fail.[33]

BACKGROUND INFORMATION

The DG Facility generation cannot remain connected to any part of the Distribution System in island mode, for many reasons, as outlined in Appendix D.

Hydro One uses a very sensitive high-speed low-set protection to clear the first occurrence of a fault on overhead circuits. This protection normally clears the fault from Hydro One in-feed in less than 100ms (from fault inception to breaker fault current interruption). Such rapid clearance is intended to be fast enough to minimize fault duration and equipment damage, and avoid melting fuses for the most common transient faults on overhead circuits such as lightning, wind and momentary foreign contacts. For overhead circuits, Hydro One also uses an automatic reclosure scheme that quickly re-energizes the circuit. The Hydro One feeder breaker or recloser is automatically reclosed after a short delay that allows time for transient faults to extinguish and motor loads to disconnect. For transient faults, automatic reclosure restores supply quickly to load customers to avoid prolonged outages[34].

Similarly, all DG Facilities must be disconnected quickly, to avoid the following:

- prolonged fault current contributions that could increase equipment damage and melt fuses;
- a sustained DG island condition;
- interference with successful Hydro One automatic reclosure that quickly restores supply to load customers for the most common transient faults; and
- asynchronous reclosure that can damage the generator(s) at DG Facility, other load customers connected to Hydro One's distribution system and/or Hydro One equipment.

[32] three-phase ground sources are any three-phase power transformers or grounding transformers that provide a ground-current return path in excess of 10 Amps to phase-ground faults on the HV side of the DGIT. That includes separate three-phase HV grounding transformers or three-phase DGIT that have star-connected HV windings with the star-point neutral connected to ground, either solidly or through a reactor.

[33] As per Section 2.3.4 Breaker Failure

[34] Typical reclosing times are 0.5 to 1 second for feeder breakers and 1.5 to 2 seconds for reclosers

At the time of manual or automatic reclosure, Hydro One low-set protection is temporarily blocked (typically for 10 seconds). This allows Hydro One timed protections to selectively isolate a faulted section of the feeder, should the fault be "permanent" (re-strike immediately after reclosure).

Additional sources of fault current from DG Facilities can reduce Hydro One in-feed to faults and cause current back-feeds. This would interfere with the time-coordination of the Distribution System protections for the selective isolation of non-transient faults. For this reason all DG Facility ground sources that can provide significant in-feed to faults on the Distribution System must be disconnected before the Hydro One source reconnects. A 500ms disconnection of DG Facility ground sources following protection operations should ensure that they will not be present when Hydro One re-energizes the circuit.

2.4.7 AUTOMATIC RECONNECTION OF GENERATION AND HV GROUND SOURCES

i) Reconnection to Hydro One's distribution system shall be a two-step process as outlined below. Both steps can occur simultaneously if the DG Facility uses HVI to synchronize generation.

ii) Step 1 outlined in Items (iii) and (iv) below shall apply only if the DGIT is required to be disconnected by an HVI as outlined in Section 2.1.13.

Step 1: Automatic DGIT Reconnection (HVI reclosing)

iii) The DGIT may be automatically re-energized using an HVI automatic reclosing scheme providing:

   a) Automatic reclosing to the HVI is initiated only when the DG Facility's interconnection protection or TT operates;

   b) The fault is not on the DG Facility side of the HVI[35];

   c) The Distribution System feeder has successfully re-energized from the normal Hydro One source; and

   d) The Distribution System voltages are stable within normal limits[36] for continuous period of 15 seconds.[37]

[35] The DG Facility's interconnection protection must be capable of distinguishing between external faults on the Distribution System and internal faults within the DG Facility as per Section 2.3.7

[36] For normal limits refer to Appendix A.3 for details on operating characteristics of Hydro One's Distribution System

[37] Reconnection of multiple generator units on a feeder may require staggered delay times. Hydro One shall assign individual delay times if this is the case.

e) Once Items (iii)(a) to (d) above are satisfied, reconnection must occur within 15 seconds.

iv) For DG Facilities requiring LSBS, the LSBS signal shall be sent 1 second before the DGIT is re-energized.

Step 2: Automatic Generator Reconnection

v) DG Facility shall not be automatically reconnected to the Distribution System until the Distribution System voltage is stabilized within 6% of nominal and the frequency is between 59.5Hz and 60.5Hz, for a definite time period defined in Item (vi) below.

vi) Automatic reconnection of the DG Facility shall include an adjustable delay that may delay the reconnection for 5 minutes.

vii) Additional requirements listed in Section 2.2.2.3 and Section 2.4.4 shall be met for this automatic reconnection following a momentary outage to occur.

viii) Should restoration attempts of Hydro One source to the Distribution System fail to re establish stable voltages within 15 minutes, automatic reconnection of the DG Facility shall be disabled.

ix) For all DG Facilities with a limit to connect through only one “normal configuration” path in accordance with their DCA, Hydro One’s operators shall give permission to the DG Facility operators to manually reconnect when stable voltages have not been restored within 15 minutes. No automatic reconnection shall take place after the 15 minutes.

BACKGROUND INFORMATION

All DG Facility generation shall be disconnected following protection operations as outlined in Section 2.4.6 above.

The following outlines what must take place before the DG Facility can reconnect. Refer to Appendix G for a detailed sequence of events and timing diagram. Figure 30 illustrates a typical successful reconnection sequence for a transient fault. Figure 31 illustrates a typical lock-out sequence for a permanent fault.

As noted in Section 2.4.6 above, at the time of manual or automatic reclosure, Hydro One low-set protection is temporarily blocked (typically for 10 seconds). This allows Hydro One timed protections to selectively isolate a faulted section of the feeder, should the fault be “permanent” (re-strike immediately after reclosure).

Blocking of the low-set protection also prevents an immediate trip upon energizing, caused by the cumulative inrush current associated with energizing customer transformers and cold-load effects.

Hydro One feeder protections should be restored to their normal state (complete with the low-set protections enabled) approximately 10 seconds after a successful manual closure or automatic reclosure. Restricting auto-reconnection of DGIT to 15 seconds allows the Hydro One protections to return to their normal state prior to re-energizing the DGIT. That allows the load customers to be restored first without the additional inrush associated with re-energizing the DGIT.

For large DG facilities not equipped with an HVI, there may be a requirement to send out a Low Set Block Signal prior to closing of the disconnect switch to energize the DGIT. (Refer to Section 2.3.15 for LSBS requirements.)

For persistent or re-occurring faults, automatic restoration attempts will be unsuccessful and the Hydro One supply will have to be manually restored. Manual restoration of the feeder will be attempted by the Hydro One Controlling Authority. That may occur within a few minutes where remote control is available. If a remote-controlled manual restoration attempt is successful, and within 15 minutes of the loss of supply, then DG Facility reconnection can proceed in accordance with Section 2.4.7.

If normal Distribution System voltages are not restored within 15 minutes, it is likely that there is a permanent fault or other serious problem with the Distribution System or Hydro One's Transmission System. This will require manual assessment and restoration by the Controlling Authority. All DG Facility automatic reconnection schemes must be disabled after 15 minutes to avoid interference with these restoration efforts.

Design Considerations

Hydro One's feeder reclosers may have multiple reclose attempts to allow sectionalizers to operate to clear the fault. Some protective devices have as many as four reclose attempts before reclosing is locked out the Distribution System voltages must be stable within normal limits[38] for a continuous period of 15 seconds that will only occur after the final successful reclose. The healthy voltage time delay must be reset every time the feeder is de energized.

The HVI automatic reclosing must initiate immediately following the 15-second healthy voltage time delay, and must be set between 0 and 15 seconds. For multiple DGITs, there

38 For normal limits refer to Appendix A.3 for details on operating characteristics of Hydro One's Distribution system)

may be a need to stagger re-energization to minimize the effects of inrush on Hydro One's distribution system and the resulting voltage sag and flicker. Hydro One shall assign the individual delay times if this is the case.

Protections for feeders with extensive underground cable sections are not likely to use instantaneous low-set protections and auto-reclosure, because cable faults are much more likely to be permanent requiring repairs. Automatic reconnection of DG Facilities would not be used for these configurations.

2.4.8 RECONNECTION OF GENERATION FOLLOWING A SUSTAINED OUTAGE OR SHUTDOWN

i) No automatic reconnection of the DG Facility shall occur following a sustained outage or shutdown – when the voltage and/or frequency out of normal operating range on any phase for more than 15 minutes for any DG Facilities limited to one connection path if stipulated in their DCA. Permission to reconnect shall be given by Hydro One's Controlling Authority in accordance with the terms of the DCA.

2.5 CONTROL AND MONITORING REQUIREMENTS

2.5.1 GENERAL

i) Control and monitoring facilities shall be required at DG Facilities connected to the Hydro One's and Distribution System for provision of real-time operating data.

ii) The DG Owner shall provide battery backup for telemetry in the event that the DG Facility is removed from Hydro One's Distribution System.

iii) Battery backup capacity shall be sufficient for the connection to be re-established.

iv) Alternatives to Item (iii) above are subject to approval by Hydro One.

v) Under the DSC and terms of the TIR, DG Owners of DG Facilities connected to Hydro One's Distribution System shall have the obligation to provide real time data pertaining to their equipment as required by the capacity at the PCC.

vi) Monitoring and control may be required as a result of Renewable Energy Supply Integration initiatives regardless of the capacity as will be determined by Hydro One.

vii) Installation capacity descriptions shall be consistent with the class definitions in the TIR listed below in Table 15 for convenience.

Table 15: DG Classification

Class	Generation Capacity at PCC
1	0 kW < DG Facility Rating ≤ 250 kW
2	250 kW < DG Facility Rating < 1500 kW
3	1.5 MW ≤ DG Facility Rating ≤ 10 MW
4	DG Facility Rating > 10 MW

viii) The requirements for real time operating information shall apply to all DG Facilities connected to Hydro One's Distribution System.

ix) The quantities and device statuses, defined below, shall be provisioned, monitored and controlled for continuous transmission to Hydro One.

x) All details shall be captured in DCA, or an appendix in the DCA as required by Hydro One and the applicable codes.

xi) Some or all of the control and monitoring requirements in the TIR may apply to DG Facilities connected to the Distribution Systems of Embedded LDCs.

2.5.2 CONTROL FACILITIES

i) Subject to the agreement between the DG Owner and Hydro One, all or some of the following remote controls, if applicable, shall be provided to Hydro One:

a) Station breakers and switchers;

b) Motorized disconnect switches;

c) Transformers' ULTC;

d) 3% and 5% voltage reduction;

e) Hold off on feeder breakers;

f) Dynamic generator output control; and

g) Other location specific devices.

ii) At any time, one and only one operating authority shall have remote control of the DG Facility.

iii) Where the DG Owner maintains an operating centre and control of the DG Facility is handed off from the DG Owner to Hydro One at scheduled times, Hydro One will consider the use of an ICCP link between the two control centres.

2.5.3 OPERATING DATA, TELEMETRY AND MONITORING

i) Quantities provided from the DG Facility shall be in engineering units.

ii) The quantities shall provide an overall end-to-end measurement error no greater than two percent of the nominal rating. The error shall include all primary, secondary and analog to digital conversions.

iii) The resolution shall meet or exceed the accuracy rating of the device performing the analog to digital conversion.

iv) Real-time data to be provided to Hydro One by the DG Owner will depend on the output rating of the DG Facility as listed below in Section 2.5.3.1 to Section 2.5.3.4.

2.5.3.1 CLASS 1 GENERATORS

i) DG Facilities with a capacity of less than or equal to 250kW shall have the provision for monitoring the disconnecting device at the PCC.

ii) Provisions for other quantities may be required and shall be determined by Hydro One.

iii) The actual implementation to install the SCADA link and modem is not required, but may be requested by Hydro One at a later date to be implemented at the DG Owner's cost within 90 days.

2.5.3.2 CLASS 2 GENERATORS

i) DG Facilities with a capacity of greater than 250kW but less than 1500kW shall provide the following information:

a) Analogue Quantities which include the following:

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 or phase to neutral voltages for single-phase generators; and

3) Three phase currents.

b) Device Statuses:

1) Consolidated Connection Status at the PCC (HVI/LVI);

2) Status of individual generating units at the DG Facility; and

3) All generation rejection selections.

c) Alarms:

1) Where facilities exist to provide independent monitoring of the interconnection protection fail as stated in Section 2.3.18 provision shall be made for an alarm signal to be generated and transmitted to Hydro One;

2) A separate alarm shall be provided for each circuit supplying the DG Facility;

3) The alarms shall identify the name of the DG Facility and the designation of the affected circuit; and

4) Hydro One shall determine requirements based on controlling authority and equipment ownership.

ii) Monitoring and control may be required as a result of Renewable Energy Supply Integration initiatives regardless of the capacity as will be determined by Hydro One.

2.5.3.3 CLASS 3 GENERATORS

i) DG Facilities with a capacity of greater than or equal to 1500kW but less than or equal to 10MW shall provide the same data as identified for Class 2 generators.

2.5.3.4 CLASS 4 GENERATORS

i) DG Facilities with a capacity of greater than 10MW shall provide the same data as identified for Class 2 generators.

2.5.3.5 TELEMETRY REPORTING RATES

i) The minimum requirements for telemetry reporting rates for DG Facilities (Class 1 to Class 4) connecting to Hydro One's Distribution System shall be as shown below in Table 16.

Table 16: Telemetry Reporting Rates[39]

Function	Performance
Data measurements	Less than 10s from change in field monitored quantity
Equipment status change	Less than 10s from field status change
Data skew	Not applicable
Scan period for data measurements	Minimum 4s
Scan period for equipment status	Minimum 4s

[39] Hydro One may poll less frequently than the minimum

2.6 TELECOMMUNICATIONS REQUIREMENTS

2.6.1 GENERAL

i) Telecommunication infrastructure is required for DG Facilities connected to Hydro One's Distribution system for provision of protection and real-time operating data.

ii) Telecommunication infrastructure shall be fast, secure, reliable, and shall meet the technical requirements for protection, control and monitoring as described in Sections 2.3 and 2.5 of the TIR.

iii) Hydro One will indicate the viable alternative technologies that may be used for Telecommunications, which may include licensed/unlicensed microwave radio, optical fiber or Carrier-based leased circuits.

iv) Cellular based Telecommunication infrastructure shall only be considered for real-time control and monitoring.

v) DG Owners shall provide the GPS coordinates of the DG Facility to assist in the evaluation of wireless communication alternatives.

2.6.2 TELECOMMUNICATIONS FACILITIES FOR TELEPROTECTION

i) A robust Telecommunication infrastructure will support the stringent reliability and latency requirements for Teleprotection.

ii) The purpose of Teleprotection is to transmit critical information about the power system conditions from one end of the protected line to the other.

iii) The proposed Telecommunication infrastructure for Teleprotection shall meet the requirements for Transfer Trip (TT) and DGEO as per Section 2.3.

iv) Telecommunication infrastructure for Teleprotection will be reviewed by Hydro One to ensure the requirements for Teleprotection are met.

2.6.3 TELECOMMUNICATIONS FACILITIES FOR REAL-TIME CONTROL AND MONITORING

i) The DG Owner shall provide real-time operating information to Hydro One as specified in Section 2.5 either directly from the station(s) as described in Item (ii) below, or from the DG Facilities' SCADA master as described in Item (iii) below.

Note: For DG Facilities connecting to the Distribution System of an Embedded LDC, the Embedded LDC shall provide real-time operating information to Hydro One from the Embedded LDC's SCADA master. For DG Facilities connecting to the Distribution System of an Embedded LDC that are not monitored by the Embedded LDC, the DG Owner shall provide monitoring to Hydro One as described in Item (ii) below.

ii) Real time operating information provided to Hydro One may be from an Intelligent Electronic Device (IED) at the DG Facility's station to Hydro One's control centre using Distributed Network Protocol (DNP 3.0 protocol):

   a) to Hydro One's wireless cellular data hub site and through the gateway to one of Hydro One's Control Centres, with the demarcation point being the wireless access point to the Service Provider's cellular network; or

   b) where Item (ii)(a) above is not feasible, through a common carrier connection to one of Hydro One's Control Centres, with the demarcation point being the Central Office nearest to DG Facility's station; or

   c) where Items (ii)(a) and (b) above are not feasible, Hydro One will suggest communication options available to a particular site.

iii) Real time operating information provided to Hydro One may be from a SCADA master through Hydro One's SCADA master using Inter-Control Center Communications Protocol (ICCP). Where the Embedded LDC has an existing ICCP link to Hydro One, all telemetry for Embedded LDC connections shall be provided through the existing ICCP link.

iv) Where modems will be used in any of the above communication methods, Hydro One will determine the modem type and requirements considering communication media, site location, reliability, and amount of data transfer. The DG Owner will provide all the required hardware and software and make arrangements, as needed, with a commercial provider of communication services to deliver the operating data to the demarcation point.

2.6.4 RELIABILITY REQUIREMENTS

2.6.4.1 TELEPROTECTION

The Telecommunication infrastructure shall comply with the following:

a) Provide at least an annual average availability of 99.65%.

b) Meet the Teleprotection dependability requirement defined as the probability of a missed command be less than 10^{-4} for DG application. As defined in IEC 60834-1.

c) Meet the Teleprotection security requirement defined as an unwanted command shall be less than 10^{-10} for DG application. As defined in IEC 60834-1.

2.6.4.2 REAL-TIME CONTROL AND MONITORING

i) The delivery of real-time data at the communication demarcation point shall have a:

   a) MTBF (Mean Time between Failure) of four (4) years; and

   b) MTTR (Mean Time to Repair) of seven (7) days.

ii) The DG Owner may be required to disconnect the DG Facility until problems are corrected if the failure rates or repair time performance in Item (i) above fails to achieve their targets by the following significant amounts:

   a) less than 2 years MTBF; or

   b) MTTR greater than 7 days.

iii) If the DG Facility is involved in a Special Protection System (SPS) or automated dispatch, the Telecommunication Mean Time to Repair (MTTR) requirement shall be 24 hours.

iv) Upon loss of telecommunications, the DG Owner is required to immediately report the failure cause and estimated repair time to the Controlling Authority.

v) Mean Time to Repair time shall start from the time when the communications was lost and not from when it was discovered.

vi) The DG Owner shall coordinate any planned interruption to the delivery of real time data with Hydro One.

2.7 REPORTING REQUIREMENTS

Note: For the purpose of this section, the word "Distributor" shall mean Hydro One if the DG Facility is connecting to Hydro One's Distribution System or shall mean an Embedded LDC is the DG Facility is connecting to an Embedded LDC's Distribution System.

2.7.1 GENERAL

i) The DG Owner shall keep a written or electronic log. This log will record the date and time, along with a description of the incident.

ii) Data files names shall contain the date and time in accordance with IEEE Standard C37.232 - Recommended Practice for Naming Time Sequence Data Files.

iii) The incidents recorded, shall include, but are not limited to those in the sections below.

iv) The DG Owner shall make the log, or a copy of the log, available for the Distributor's review upon request, within five (5) working days of that request or as specified in the DCA.

v) The DG Facility shall monitor:
   a) Phase Voltages;
   b) Neutral to earth voltage;
   c) Frequency;
   d) Phase and neutral amps;
   e) Active Power (kW or MW);
   f) Reactive Power (kVAr or MVAr);
   g) Status of switching devices which are part of a protection and control scheme; and
   h) Alarm conditions.

vi) The DG Facility shall provide an alarm to the Distributor when there is a failure of recording or logging capability.

vii) The recording device shall be capable of recording event time in either UTC or Eastern Standard Time.

viii) DG Facilities rated greater than 250kW and less than 10MW reporting protection initiated events shall meet the following performance requirements:

a) The maximum difference in time stamps produced by different devices on the network for the same event shall be 4ms or less.

b) The maximum difference between the time generated by the internal clock and the actual time [e.g. - Eastern Standards Time (EST) or Coordinated Universal Time (UTC) shall be limited to 4ms.

ix) DG Facilities rated 10MW and greater reporting protection initiated events shall meet the following performance requirements:

a) The maximum difference in time stamps produced by different devices on the network for the same event shall be 1ms or less.

b) The maximum difference between the time generated by the internal clock and the actual time [e.g. - Eastern Standards Time (EST) or Coordinated Universal Time (UTC) shall be limited to 1ms.

2.7.2 POWER QUALITY RECORDING

i) Power quality recording shall be provided for DG Facilities rated greater than 250kW.

ii) The PQ device shall generate an alarm if there is a loss of signal at an AC input terminal.

iii) The PQ device shall be capable of communicating with Hydro One monitoring facilities using ION 2.0, DNP 3.0 and GPSTRUETIME/DATUM protocols via RS 232/485 or Ethernet ports.

iv) The PQ device shall be capable of recording impulsive transients in the milliseconds range (monitoring possible to 7 kHz).

v) The PQ device shall be capable of recording low frequency oscillatory transients (f < 5 kHz).

vi) The PQ device shall be capable of recording medium frequency transients (5 kHz < f < 500 kHz).[40]

vii) The PQ device shall be capable of recording sags/swells/interruptions.

viii) The PQ device shall be capable of capturing voltage and current channels simultaneously.

[40] Assuming that the device selected for PQ monitoring has a maximum sampling rate of 256 samples per cycle (~ 15 kHz) the device will only be capable of monitoring medium frequency transients up to 7 kHz.

ix) The PQ device shall be capable of recording the duration of voltage sag and swell events based on programmable setpoints.

x) Waveforms, rms voltage variations, trends, and histograms shall be reported in IEEE P1159.3 PQDIF format.

2.7.3 DISTURBANCE FAULT RECORDING

i) Disturbance reporting shall be provided for each class of DG Facility as specified in Items (iii), (iv) and (v) below.

ii) Data file format shall be compatible with - IEEE Std C37.111-1999 "IEEE Standard Common Format for Transient Data Exchange (COMTRADE) for Power Systems." This format shall be used when sharing files.

iii) DG Facilities rated less than or equal to 250kW shall provide waveforms from IEDs used for protection.

iv) DG Facilities rated greater than 250kW up to 1500kW shall provide:

  a) a minimum rate of 240Hz (4 samples/cycle) at a minimum resolution of 0.05% of full scale (alternatively a 12 bit resolution is acceptable); and

  b) a minimum record duration shall be the sum of 4 cycles of pre-fault + 2 cycles post fault + total clearing time of longest time delayed protection (i.e. when phase protections are set at 500ms delay and a 85ms breaker is used, the total time for recording would be 66ms + 500ms +85ms + 33ms = 685ms).

v) DG Facilities rated 1500kW or greater shall provide:

  a) a minimum rate of 1 kHz (16 samples/cycle) at a minimum resolution of 0.05% of full scale (alternatively a 12 bit resolution is acceptable);

  b) a minimum duration of 1 second; and

  c) a minimum pre-fault duration of 250ms.

vi) All reports shall provide unfiltered records. If filtered records are also available they shall be included in the report as well.

vii) Multiple consecutive triggered disturbance records shall be acceptable, if required, to achieve the 1 second duration requirement.

2.7.4 SEQUENCE OF EVENTS RECORDING

i) Sequence of Event reporting shall be provided for each class of DG Facility as specified in Items (iii), (iv) and (v) below.

ii) Recorded points shall include:

a) the generator connection status (individual units);

b) the Transfer Trip signal status;

c) the Distributed Generation End Open (DGEO) signal status;

d) which relays operated (targets & description); and

e) any available sequence of events records (SER) related to the above.

iii) DG Facilities rated less than or equal to 250kW shall provide SER reporting from IEDs used for protection.

iv) DG Facilities rated greater than 250kW and less than 10MW shall provide:

a) SER from switching devices which are part of a protection and control scheme; and

b) Event records with resolution of 1ms.

v) DG Facilities rated 10MW or greater shall also provide in addition to the requirements in Item (iv) above:

a) Events within the same facility recorded to within 1ms accuracy if reporting is required to a compliance authority other than Hydro One.

2.8 METERING REQUIREMENTS

Metering requirements vary with the type and intent of the DG Facility. Please consult the IESO Market Rules and Section 5 of the Distribution System Code for details. Hydro One has published a Metering policy for DG Facilities and it is located at the following link:

http://www.hydroone.com/Generators/Pages/Feed-inTariff.aspx

2.9 COMMISSIONING AND VERIFICATION REQUIREMENTS

i) Commissioning and Verification shall be in accordance with the OEB Distribution System Code Connection Process as outlined in Appendix F.1.

ii) Hydro One may witness any Commissioning and Verification of DG Facilities greater than 10kW.

iii) A specific Commissioning and Verification plan shall be developed that corresponds to the specific design of the DG Facility and implemented using the Hydro One Cover Process outlined in Section 2.9.1.

iv) The specific Commissioning and Verification plan in Item (iii) above shall incorporate the Generic Requirements as outlined in Section 2.9.2.

2.9.1 COVER PROCESS

i) The DG Owner shall use a "Confirmation of Verification Evidence Report" (COVER) to track the DG Facility's Commissioning and Verification plans and execution. The complete COVER form will be provided to the DG Owner at the appropriate stage of the project.

2.9.2 COMMISSIONING AND VERIFICATION GENERIC REQUIREMENTS

i) Testing of the DG Facility interconnection system shall conform to IEEE Standard 1547.1 – "*Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems*".

ii) Hydro One's participation in the commissioning of the DG Facility shall be limited to those protection and control systems that impact Hydro One's Distribution System.

iii) Commissioning of the protection and control systems shall be complete and thorough.

iv) Testing must include end-end verification of all inputs to the protection and control schemes (instrument transformers, breaker positions, transfer trips, distributed generator end open schemes), correct processing of those inputs by the protection and control systems for anti-islanding and clearance of external faults, and end-end verification of all outputs - breaker tripping, breaker failure initiation, closing interlocks, alarms, and telemetry.

v) The expected commissioning testing and supporting documentation must include:

a) Instrument transformer checks (insulation, ratio/polarity, excitation and resistance results);

b) Breaker timing trip tests for those breakers used to disconnect the DG Facility from the Distribution System as a result of protection operations;

c) Verification of the transformer and neutral reactor impedances that impact the DG Facility's ground integration with the Distribution System and correct connection, where applicable;

d) Relay setting field work sheets (showing the measured results of the relay calibration checks). Relay element settings/directioning are to be confirmed by AC secondary injection;

e) Voltage measurements for any external power supplies used to supply the protections shall be recorded;

f) Verification that all AC and DC measurements have test equipment traceable to NRC standards;

g) Functional tests confirming the protection and control logic and timer settings;

h) Verification of test trips and alarm processing. Monitoring of breakers outputs using suitable indicators can be used to avoid repeated tripping of the same from different protections, but at least one live trip test per breaker (where the breaker is proven to open) needs to be demonstrated;

i) Verification of control interlocks in protections;

j) Verification of synchronizing system and synch-check controls;

k) Voltage phasing checks (prior to first connection);

l) Secondary load readings, voltage and current phasor checks (immediately after first connection) to prove correct magnitude and phase angle of all secondary AC voltage and current circuits correspond to primary quantities. Primary current, voltage, MW and MVAr values shall be calculated from the measured secondary values and compared to known primary quantities at adjacent locations; and

m) Verification of Transfer Trips and DGEO end-end checks. This will require participation and coordination with Hydro One.

vi) The DG Owner shall make modifications to correct any problems that are found during commissioning.

BACKGROUND INFORMATION

IEEE Std. 1547.1 – "*Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems*" specifies the type, production, and commissioning tests that shall be performed to demonstrate that the interconnection functions and equipment of the distributed resources (DR) conform to IEEE Std. 1547.

2.9.3 DOCUMENTATION OF TEST RESULTS

i) Documentation of Test Results shall be provided as outlined in the COVER sections as follows:

a) In accordance with Section 6 of "Electrical Safety" all DG Owners must provide a letter signed and stamped by a Professional Engineer registered in the province of Ontario stating that their equipment and installation meets CSA and/or other applicable electrical safety standards, prior to ready for Service Date;

b) In accordance with Appendix F of DSC and Section 8 of the "Test Summary Reports" the DG Owner of any DG Facility larger than 10kW, at Hydro One's request, shall provide Hydro One with a summary of testing results, including any certificates of inspection or other applicable authorizations or approvals certifying that any of the DG Owner's new, modified or replacement facilities have passed the relevant tests and comply with all applicable instruments and standards referred to in the code;

c) As-constructed drawings (single line diagram showing protection and metering, AC and DC schematics, final relay settings, testing and commissioning results for interconnection protection etc.) shall be submitted to the Distributor for its records, as stipulated in the Distribution Connection Agreement; and

d) The completed documentations shall clearly indicate the station, protection designation, settings date, test date, the name of the tester(s), relay type (manufacturer and model), test equipment details (manufacturer, model, serial number, accuracy, last calibration date), instrument transformer ratios. There shall be a cross-reference to the submitted design documentation (drawing numbers and revision).

ii) The DG Owner shall keep the information provided in Item (i) above for a period of seven (7) years.

2.10 MAINTENANCE REQUIREMENTS

2.10.1 PROTECTION AND CONTROL SYSTEMS EQUIPMENT

i) The DG Owner shall re-verify its interconnection Protection and Control sub-systems that impact Hydro One's Distribution System on a periodic basis, according to the following schedule:

a) whenever any protection and control sub-system equipment requires replacement, design modification or changes to settings[41];

b) every 8 years for IED-based protection sub-systems that employ comprehensive self-diagnostic features[42] to detect and provide alarm telemetry to Hydro One for internal sub-system failures;

c) every 4 years for electromechanical or other non IED-based protection sub systems that do not employ comprehensive self-diagnostic features to detect and provide alarm telemetry to Hydro One for internal sub-system failures; and

d) The above periodic re-verification intervals may need to be made more frequent if required to restore or sustain the safety or reliability of Hydro One's Distribution System to acceptable levels of performance, as required by the Distribution System Code and the Conditions of Service.

ii) The protection and control systems that require periodic maintenance are the same ones that were required to be confirmed and verified during commissioning as part of the COVER process (Section 2.9: Commissioning and Verification Requirements).

iii) Within three (3) months of Connection, the DG Owner shall provide Hydro One with their proposed Protection and Control re-verification program (including test procedures and schedules). It is expected that the re-verification tests will be similar to the tests conducted during commissioning, with the exception of checking equipment conditions that are obviously proven to be functional during normal day-to day operation as described below.

41 Hydro One must be advised of and approve all interconnection equipment replacement, design modification and setting changes

42 Hydro One will assess the adequacy of the self-diagnostic features of protection sub-systems based on the same criteria used for assessing Hydro One feeder protections

a) Instrument transformer checks (insulation, ratio/polarity, excitation and resistance results) – *should not require re-verification providing secondary load readings of Item (l) below are correct);*

b) Breaker timing trip tests for those breakers used to disconnect the DG Facility from the Distribution System as a result of protection operations – *may not be required if adequate SER or DFR records are available to show correct timing has been sustained*;

c) Verification of the transformer and neutral reactor impedances that impact the DG Facility's ground integration with the Distribution System and correct connection, where applicable - *should not require re-verification unless this equipment is replaced*;

d) Relay setting field work sheets (showing the measured results of the relay calibration checks). Relay element settings/directioning are to be confirmed by AC secondary injection – *shall require re-verification*;

e) Voltage measurements for any external power supplies used to supply the protections shall be recorded – *shall require re-verification*;

f) Verification that all AC and DC measurements have test equipment traceable to NRC standards – *shall require re-verification*;

g) Functional tests confirming the protection and control logic and timer settings - *shall require re-verification*;

h) Verification of test trips and alarm processing. Monitoring of breakers outputs using suitable indicators can be used to avoid repeated tripping of the same from different protections, but at least one live trip test per breaker (where the breaker is proven to open) needs to be demonstrated - *shall require re-verification*;

i) Verification of control interlocks in protections - *shall require re-verification*;

j) Verification of synchronizing system and synch-check controls – *should not require re-verification providing the DG Facility has been connected and disconnected on a regular basis (at least once per month)*;

k) Voltage phasing checks (prior to first connection) – *should not require re-verification unless three-phase power equipment is replaced*;

l) Secondary load readings, voltage and current phasor checks (immediately after first connection) to prove correct magnitude and phase angle of all secondary

AC voltage and current circuits correspond to primary quantities. Primary current, voltage, MW and MVAr values shall be calculated from the measured secondary values and compared to known primary quantities at adjacent locations - *shall require re-verification*; and

m) Verification of Transfer Trips and DGEO end-end checks. This will require participation and coordination with Hydro One - *shall require re-verification*.

iv) The DG Owner shall make modifications to correct any problems that are found during re-verification.

v) Within thirty (30) working days of receiving the above documentation or as required by the Code, Hydro One shall notify the DG Owner that it:

a) agrees with the proposed re-verification program and test procedures; or

b) requires changes in the interest of safety or maintaining the reliability of the Distribution System. Such request for changes shall be sent to the DG Owner promptly.

vi) For those tests that require Hydro One's participation or witnessing, the DG Owner shall provide Hydro One with no less than fifteen (15) working days notice prior to the test date.

vii) All tests shall be coordinated and approved ahead of time through the normal outage and work management system planning processes.

viii) The DG Owner shall complete the re-verification in accordance with Item (v) above and submit complete documentation of the test results to Hydro One within one month of the completed tests.

BACKGROUND INFORMATION

Maintenance requirements are equivalent to what Hydro One requires for re-verification of its own facilities that have similar potential impact to the Distribution System.

2.11 CONNECTION PROCESS REQUIREMENTS

For Connection Process Requirements please visit www.HydroOne.com and look for "Generators" or click on the following link:

http://www.hydroone.com/Generators/Pages/Feed-inTariff.aspx

3 REFERENCES

The following documents are subject to revisions from time to time. When the stated version of the following documents is superseded by an approved revision, then the approved revision shall apply.

[1] **Ontario Energy Board Distribution System Code Appendix F** - Process and Technical Requirements for Connecting Embedded Generation Facilities - Section F.2 Technical Requirements

[2] **Ontario Energy Board Distribution System Code** – http://www.oeb.gov.on.ca

[3] **OESC - 24th Edition 2009** – Ontario Electrical Safety Code, - Twenty-fourth edition

[4] **CSA C22.1-2009** - Canadian Electrical Code, Part I Safety Standard for Electrical Installations - Twenty-first edition

[5] **CSA C22.2** - Canadian Electric Code Part II

[6] **CSA C22.3** - Canadian Electric Code Part III (Electricity Distribution and Transmission Systems).

[7] **CAN/CSA C22.3 No. 9-2008** - Interconnection of Distributed Resources and Electricity Supply Systems

[8] **CSA C235-83-CAN3** - Preferred Voltage Levels for AC Systems, 0 to 50,000 V Electric Power Transmission and Distribution

[9] **CAN/CSA C22.2 No. 257-06** - Interconnecting Inverter-Based Micro-Distributed Resources to Distribution Systems.

[10] **CAN/CSA-CEI/IEC 61000-4-4-06** – Electromagnetic Compatibility (EMC) – Part 4-4 Testing and Measurement Techniques – Electrical Fast Transient/Burst Immunity Test (Adopted CEI/IEC 61000-4-4:2004, second edition, 2004-07)

[11] **CAN/CSA-CEI/IEC 61000-4-2-01** – Electromagnetic Compatibility (EMC) – Part 4-2 Testing and Measurement Techniques – Electrostatic Discharge Immunity Test (Adopted CEI/IEC 61000-4-2:1995 + A1:1998, edition 1.1, 1999-05)

[12] **CAN/CSA-CEI/IEC 61000-4-30-04** – Electromagnetic Compatibility (EMC) – Part 4-30: Testing and Measurement Techniques – Power Quality Measurement Methods (Adopted CEI/IEC 61000-4-30:2003, first edition, 2003-02)

[13] **CAN/CSA-CEI/IEC 61000-4-15-03** - Electromagnetic Compatibility (EMC) – Part 4-15: Testing and Measurement Techniques – Section 15: Flickermeter—Functional and Design Specifications (Adopted CEI/IEC 61000-4-15:1997 + A1:2003, edition 1.1, 2003 02)

[14] **CAN/CSA-CEI/IEC C61000-3-7-09** - Electromagnetic Compatibility (EMC) – Part 3-7: Limits: Assessment of Emission Limits for Fluctuating Loads in MV, HV and EHV Power Systems (Adopted IEC/TR 61000-3-7:2008, second edition, 2008-02)

[15] **CAN/CSA-C61000-3-06-09** - Electromagnetic compatibility (EMC) - Part 3-6: Limits Assessment of emission limits for the connection of distorting installations to MV, HV and EHV power systems (Adopted IEC/TR 61000-3-6:2008, second edition, 2008-02, with Canadian deviations)

[16] **UL 1741** - Inverters, Converters, and Controllers for Use in Independent Power Systems

[17] **IEEE 1547-2003** - IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems

[18] **IEEE C37.232** - Recommended Practice for Naming Time Sequence Data Files

[19] **IEEE C37.111-1999** - IEEE Standard Common Format for Transient Data Exchange (COMTRADE) for Power Systems

[20] **IEEE 1547.1-2005** - IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems

[21] **IEEE P1547.2/D11** - Draft Application Guide for IEEE Standard 1547, Interconnecting Distributed Resources with Electric Power Systems

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

[23] **IEEE 519-1992** - IEEE recommended practices and requirements for harmonic control in electrical power systems

[24] **IEEE 929-1988** - IEEE recommended practice for utility interface of residential and intermediate photovoltaic (PV) systems

[25] **IEEE C37.90.1-2002** - IEEE Standard for Surge Withstand Capability (SWC) Tests for Relays and Relay Systems Associated with Electric Power Apparatus

[26] **IEEE C37.90.3-2001** - IEEE standard electrostatic discharge tests for protective relays

[27] **IEEE 1159-1995** - IEEE Recommended Practice for Monitoring Electric Power Quality.

[28] **IEEE 1453-2004** - IEEE Recommended Practice for Measurement and Limits of Voltage Flicker on AC Power Systems

[29] **NPCC Directory D12** – NPCC Regional Reliability Reference Directory #12 Under Frequency Load Shedding Program Requirements

[30] **CAN/CSA-C71-1-99** – Insulation Co-ordination – Part 1: Definitions, Principles and Rules (Adopted CEI/IEC 71-1:1993, seventh edition, 1993-12, with Canadian deviations)

[31] **CAN/CSA-C71-2-98** – Insulation Co-ordination – Part 2: Application Guide (Adopted CEI/IEC 71-2:1996, third edition, 1996-12, with Canadian deviations)

[32] **CSA C22.2 No. 31-04** - Switchgear Assemblies

[33] **CSA C22.2 No. 107.1-01** - General Use Power Supplies

[34] **IEEE C37.90-2005** - IEEE Standard for Relays and Relay Systems Associated with Electric Power Apparatus

[35] **IEEE C37.90.2-2004** - IEEE Standard for Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers

[36] **CAN/CSA-C60044-1-07** - Part 1: Current Transformers (Adopted CEI/IEC 60044-1:1996 + A1:2000 + A2:2002, edition 1.2, 2003-02, with Canadian deviations)

[37] **CAN/CSA-C60044-2-07** - Part 2: Inductive Voltage Transformers (Adopted CEI/IEC 60044-2:1997 + A1:2000 + A2:2002, edition 1.2, 2003-02, with Canadian deviations)

[38] **CAN/CSA-C60044-3-07** - Part 3: Combined Transformers (Adopted CEI/IEC 60044 3:2002, second edition, 2002-12, with Canadian deviations)

[39] **CAN/CSA-C60044-5-07** - Part 5: Capacitor Voltage Transformers (Adopted CEI/IEC 60044-5:2004, first edition, 2004-04, with Canadian deviations)

[40] **CAN/CSA-C60044-6-07** - Part 6: Requirements for Protective Current Transformers for Transient Performance (Adopted CEI/IEC 44-6:1992, first edition, 1992-03, with Canadian deviations)

[41] **CAN/CSA-C60044-7-07** - Part 7: Electronic Voltage Transformers (Adopted CEI/IEC 60044-7:1999, first edition, 1999-12, with Canadian deviations)

[42] **CAN/CSA-C60044-8-07** - Part 8: Electronic Current Transformers (Adopted IEC 60044 8:2002, first edition, 2002-07, with Canadian deviations)

[43] **IEEE C57.13-2008** - IEEE Standard Requirements for Instrument Transformers

[44] **IEEE C57.13.1-2006** - IEEE Guide for Field Testing of Relaying Current Transformers

[45] **IEEE C57.13.2-2005** - IEEE Standard Conformance Test Procedures for Instrument Transformers

[46] **IEEE 242-2001** - IEEE Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems - IEEE Buff Book

[47] **IEEE 1109-1990** - Guide for the Interconnection of User-Owned Substations of Electric Utilities

[48] **IEEE 1001-1988** - IEEE Guide For Interfacing Dispersed Storage and Generation Facilities with Electric Utility Systems

[49] **IEEE 493-2007** - Gold Book - IEEE Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems

[50] **IEEE 1100-2005** - Emerald Book - IEEE Recommended Practice for Powering and Grounding Electronic Equipment

[51] **IEEE 1250-1995** - IEEE Guide for Service to Equipment Sensitive to Momentary Voltage Disturbances

[52] **IEEE 100-1997** - IEEE Standard Dictionary of Electrical and Electronics Terms

[53] **IEEE 315-1975** - Graphic Symbols for Electrical and Electronics Diagrams

[54] **IEEE C37.2-2008** - IEEE Standard Electrical Power System Device Function Numbers, Acronyms, and Contact Designations

[55] **IEEE C37.1-2007** - IEEE Standard for SCADA & Automation Systems

[56] **IEEE 80-2000** - Safety in AC Substation Grounding

[57] **IEEE 81-1983** - Guide for Measuring Earth Resistivity, Ground Impedance, and Earth Surface Potentials of a Ground System Part 1: Normal Measurements

[58] **IEEE C62.23-1995** - IEEE Application Guide for Surge Protection of Electric Generating Plants

[59] **IEEE C37.29-1981** - IEEE Standard for Low-Voltage AC Power Circuit Protectors Used in Enclosures

[60] **CAN/CSA-C2.1-06** - Single-Phase and Three-Phase Liquid-Filled Distribution Transformers

[61] **CAN/CSA-C2.2-06** - Pole-Mounted, Single-Phase Distribution Transformers for Electric Utilities

[62] **CAN/CSA-C227.3-06** - Low-Profile, Single-Phase, Pad-Mounted Distribution Transformers with Separable Insulated High-Voltage Connectors

[63] **CAN/CSA-C227.4-06** - Three-Phase, Pad-Mounted Distribution Transformers with Separable Insulated High-Voltage Connectors

[64] **CAN/CSA-C88-M90** - Power Transformers and Reactors

[65] **IEEE C57.12** - IEEE Standard General Requirements for Liquid Immersed Distribution, Power and Regulating Transformers

[66] **IEEE C57.12.13** Conformance Requirements for Liquid Filled Transformers Used in Unit Installations including Unit Substations

[67] **IEEE C57.13** IEEE Standard Requirements for Instrument Transformers

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[71] **IEEE C37.30-1997** IEEE Standard Requirements for High Voltage Switches

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[74] **CSA C22.2 No. 193-83 (R2000)** High-Voltage Full-Load Interrupter Switches

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[77] **NEMA LA-1** – Surge Arresters

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A APPENDIX A – HYDRO ONE SYSTEM CHARACTERISTICS *(INFORMATIVE)*

This section describes the characteristics of Hydro One's Distribution System and identifies aspects that must be taken into consideration when designing a generation connection. The DG Owner must be able to operate within the ranges specified in this section. In the TIR, Distribution System may refer to either three phase systems or single phase systems operating at voltages of 50kV and below – includes systems falling under the definition of distribution lines and sub-transmission lines. This section contains no requirements for the connection of DG Facilities and has been provided for informational purposes only.

A.1 GENERAL CHARACTERISTICS

Most distribution circuits or feeders in Hydro One's distribution system are supplied radially from a single substation (point of supply). In some areas, some feeders may have alternate points of supply, but will be operated with more than one source of supply only momentarily during switching operations. Hydro One's distribution feeders operate at the following voltages (phase-phase/phase-neutral): 44kV (3-Wire), 27.6/16kV, 25/14,4kV, 13.8/8kV, 12.48/7.2kV, 8.32/4.8kV, 4.16/2.4kV.

A.2 SYSTEM FREQUENCY

The nominal frequency of Hydro One's system is 60Hz. During normal operation (steady state), the frequency may deviate from 59.3Hz to 60.5Hz, or as supplied by the transmission system. Under contingencies the frequency deviations may be larger.

A.3 VOLTAGE

The CSA Standard CAN3-C235-83 "Preferred Voltage Levels for AC Systems, 0 to 50,000V Electric Power Transmission and Distribution" provides general guidance for the steady state service voltage levels on the distribution system. Customers supplied by the distribution feeder must have voltage levels in accordance with this standard, with and without distributed generation supplying power for minimum and maximum loading conditions. The operating voltages found on the distribution feeder vary depending on load variation, generation variation and contingency situations. Hydro One's standard for voltages on the Distribution System at the point of delivery during normal operation is typically in the range of +/- 6% of nominal voltage as shown in Table 17.

These values may be exceeded under abnormal conditions. Voltage transients and swells can occur on the distribution system at any time due to lightning strikes, single phase to ground faults, and switching, among others.

Table 17: Voltage Limits 0 to 50 kV on Distribution System

Low Limit (% of nominal)	Nominal Voltage (%)	High Limit (% of nominal)
94	100	106

A.4 VOLTAGE REGULATION

Hydro One utilizes voltage regulating devices throughout the distribution system to maintain an adequate voltage profile along the feeders and ensure that customers receive voltages in the range specified in CSA Standard CAN3-235-83. These regulating devices include line voltage regulators, regulating stations and transformer under-load tap changers at the Transformer Station (TS) or Distribution Station (DS). Hydro One operates all voltage regulating devices on its distribution system to 125V ±1.5V on a 120V base.

A.5 VOLTAGE AND CURRENT UNBALANCE

Voltage unbalance due to unbalanced loading and single phase voltage regulation is typically under 2% but may be higher in some areas. The voltage unbalance is calculated using the root-mean square (rms) voltage levels at the fundamental frequency measured at the service entrance (Point of Connection) under no-load and no generation as in the following equation:

$$Voltage\ Unbalance\ (\%)\quad 100\ \times \frac{V_2}{V_1}$$

$$where\ V_2\ is\ the\ negative\ sequence\ voltage\ (fundamental\ frequenc\ \ component)$$
$$V_1\ is\ the\ positive\ sequence\ voltage\ (fundamenta\ \ frequenc\ \ component)$$

Current unbalance is usually 10-20% of total feeder load current but may be higher in some areas. During abnormal conditions such as faults and single pole reclosing, the unbalance may be very high (current unbalance may be significantly higher than 20%).

A.6 POWER QUALITY

In Hydro One's distribution system, all interconnected equipment must comply with Hydro One's standards for power quality. IEEE Std. 519, *IEEE Recommended Practices and Requirements for Harmonic Control in Electric Power Systems,* has been accepted by industry to provide guidance for appropriate performance and power quality limits such as voltage flicker and harmonic contribution limits. This standard states that the recommended practice for utilities is to limit individual frequency voltage harmonics to 3% of the fundamental frequency and the total voltage harmonic distortion (THD) to 5% on the utility side of the PCC.

A.7 FAULT LEVELS

Fault levels on Hydro One's distribution system vary greatly throughout the system and are in accordance with the Transmission System Code Appendix 2. Some factors such as location, generation pattern and contingencies all contribute to varying fault levels. These fault levels may also change with time as the system expands and new generation comes online.

A.8 SYSTEM GROUNDING

Hydro One's distribution facilities are typically operated as uni-grounded (for three-phase 3 wire systems) or multi-grounded (for three-phase 4-wire systems). The transformer neutral at the substation is either solidly grounded, without any impedance, or effectively grounded through a low impedance at the station through a neutral reactor, a resistor, or a grounding transformers to limit the fault levels on ground faults.

A.9 DISTRIBUTION SYSTEM FEEDER PROTECTION

The general feeder protection scheme utilized on Hydro One's distribution system where DG Facilities are connecting is described below for M Class feeders emanating from TSs. The feeder protections can be divided into three states:

High Set Instantaneous – Instantaneous protection for close-in feeder faults is usually set to the first tap on the feeder and traditionally employed High Set 50A/50NA elements. The current Hydro One standard for feeders with DG Facilities connected is to use the Zone 1 distance (21 – Phase & Ground) element to set the High Set Instantaneous protection.

Low Set Instantaneous – Instantaneous protection for faults on the entire length of the feeder. This is used primarily as a fuse saving scheme to clear transient faults before fuse elements start melting. It is traditionally utilized using Low Set 50B/50NB elements. The current Hydro One standard for feeders with DG Facilities connected is to use the Zone 2 distance (21 – Phase & Ground) element to set the Low Set Instantaneous protection.

Timed – Directionally supervised 51/51N overcurrent elements load/fault discrimination are used for timed protection of Hydro One's distribution feeders. They are set to detect and clear faults in their required zone. All timed overcurrent elements on the distribution system are coordinated with each other to ensure that a minimum number of customers are affected in the case of permanent faults. For the timed overcurrent elements to function properly, all DG Facility sources (both positive sequence and zero sequence sources) need to be removed from the distribution system – refer to the requirements in Section 2.1.13 High Voltage Interrupting Device.

F Class feeders radiating from DSs have varying levels of sophistication in their protection schemes.

A.10 AUTOMATIC RECLOSING (FAULT CLEARING)

Hydro One's Distribution System utilizes automatic reclosing to quickly clear non permanent faults on the sub-transmission and distribution system, thus, quickly restoring supply. In general, feeder circuit breakers at Transmission Stations use single-shot reclosing. Reclosers at Distribution Stations and other locations along the distribution feeder may use single-shot or multi-shot automatic reclosing. Reclosers can trip a single phase, when single phase loads are connected to the feeder, or all three phases. If after a number of preset reclose attempts the fault persists, then the recloser will lockout and stay open (single phase or three phases will be tripped). The reclose "dead time" (time that the distribution line is de-energized between reclose attempts) varies depending on location and type of recloser. That data can be obtained from Hydro One along with all other relevant protection data.

A.11 PHASING

Conductor phasing may not be standardized and as such, the phase sequence and the direction of rotation can be obtained from Hydro One.

A.12 MULTIPLE SOURCE (NETWORKED) SYSTEM

In some areas of Hydro One's Distribution System, there may be instances where portions of a distribution feeder are supplied from two different sources (such as during switching events). There is added complexity in these instances as the risk of out-of-phase reclosing for a DG Facility is now from multiple possible sources.

A.13 FREQUENCY OF INTERRUPTION

Hydro One's distribution feeders are mainly unshielded overhead lines spanning vast distances. They are equipped with insulation levels adequate to withstand expected voltages. Lightning strikes directly to Hydro One's distribution line result in flashovers of the insulators on the feeder and result in protection systems tripping the distribution line. The faults may be temporary in which case a successful reclose will occur. Most faults on overhead distribution lines are temporary in nature. If they are permanent, and they trip the line, repair crews are dispatched and repair the feeder.

Due to the vast distances of the lines and the possibility of frequent momentary trips, the DG Facility proponent may consider a design that will be suitable for these conditions such as auto-restart.

A.14 ABNORMAL CONDITIONS

Many disturbances can occur on the distribution system at varying frequencies. These disturbances can include, but are not limited to the following:

- Faults on the system;
- Frequency excursions;
- Partial or complete loss of load;
- Transient overvoltages – caused by lightning strikes or switching operations;
- Temporary overvoltages;
- Single phasing of the three phase system – caused by Hydro One's protection equipment, switching or broken conductors; and
- Ferroresonance overvoltages due to resonance conditions.

B APPENDIX B – DEVICE NUMBER DESCRIPTION *(INFORMATIVE)*

The following is a list of relevant device numbers and their meaning:

21 - Distance Relay
25 - Synchronizing or Synchronism-Check Device
27 - Undervoltage Relay
31 - Separate Excitation Device
32 - Directional Power Relay
37 - Undercurrent or Underpower Relay
42 - Running Circuit Breaker
46 - Reverse-phase or Phase-Balance Relay
47 - Phase-Sequence Voltage Relay
49 - Machine or Transformer Thermal Relay
50 - Instantaneous Overcurrent
51 - AC Time Overcurrent Relay
52 - AC Circuit Breaker
53 - Exciter or DC Generator Relay
55 - Power Factor Relay
57 - Short-Circuiting or Grounding Device
59 - Overvoltage Relay
60 - Voltage or Current Balance Relay
61 - Machine Split Phase Current Balance
64 - Ground Detector Relay
67 - AC Directional Overcurrent Relay
68 - Blocking Relay
79 - AC-Reclosing Relay
81 - Frequency Relay
86 - Lockout Relay
87 - Differential Protective Relay
88 - Auxiliary Motor or Motor Generator
89 - Line Switch
90 - Regulating Device
91 - Voltage Directional Relay
92 - Voltage and Power Directional Relay

C APPENDIX C – NEUTRAL REACTOR AND GROUNDING TRANSFORMER IMPEDANCE CALCULATIONS FOR DG FACILITIES *(INFORMATIVE)*

C.1 INTERCONNECTING TO HONI'S 4-WIRE DISTRIBUTION SYSTEM

For Inverter based DG Facilities connecting to Hydro One's 4-wire Distribution System, grounding transformers can be used to serve as a ground source whenever the DGIT winding configuration is not Wye-Ground:delta. Examples 1 and 2 are to provide the impedance calculations for Inverter based DG Facilities that require separate grounding transformers. As per Section 2.1.11 Grounding, the Zero Sequence Reactance (X_{DG0}) of the DG Facility should be about 0.6 times the base impedance, where the base impedance is calculated based on the total MVA rating of the DG Facility.

Example 1: **A 10MVA DG Facility is connected at 27.6kV, via ten parallel 1MVA DGITs, and the DGITs have Delta-connected 27.6kV windings.**

Base impedance = $27.6kV^2$ / (10 x 1MVA) = 76.2Ω,
Then the required Zero Sequence Reactance of the DG Facility is:
X_{DG0} = 0.6 x 76.2Ω ± 10% = 45.7Ω ± 10%

Therefore, if a separate 27.6kV zig-zag grounding transformer is used to serve as a ground source, the impedance of the grounding transformer should be 45.7Ω per phase with a tolerance of ±10%.

Example 2: **A 2MVA DG Facility is connected at 27.6 kV, via a single 2MVA DGIT, and the DGIT has Wye-Ground:wye-Ground windings.**

Base impedance = $27.6kV^2$ / 2MVA = 381Ω,
Then the required Zero Sequence Reactance of the DG Facility is:
X_{DG0} = 0.6 x 381Ω ± 10% = 228.6Ω ± 10%

Therefore, if a separate 27.6kV zig-zag grounding transformer is used to serve as a ground source, the impedance of the grounding transformer should be 228.6Ω per phase with a tolerance of ±10%.

The continuous rating of the grounding devices shall be able to handle the maximum expected voltage unbalance with margin. As per Hydro One's Conditions of Service, the voltage unbalance on Hydro One feeders can reach 5%. Therefore, the grounding device should be sized for a minimum of 5% continuous voltage unbalance. The short time (5 sec) fault rating shall be sized for the maximum fault current that will flow through the grounding device for a close-in fault.

For Inverter based DG Facilities connecting to Hydro One's 4-wire Distribution System, neutral reactors may be required to limit the fault current contributions from DG Facilities for ground faults on the interconnected feeder when the DGIT winding configuration is Wye-Ground:delta. Examples 3 and 4 are to provide the impedance calculations for neutral reactors that can be connected between the neutral of Wye-Ground:delta DGITs and the ground. As per Section 2.1.11 Grounding, the Zero Sequence Reactance (X_{DG0}) of the DG Facility should be about 0.6 times the base impedance, where the base impedance is calculated based on the MVA rating of individual DGIT. The size of neutral reactor (X_n) for each DGIT should be one third of the required Zero Sequence Reactance of the neutral reactor ($X_{0,NGR}$):

Example 3: **A 10MVA DG Facility is connected at 27.6kV, via ten parallel 1MVA DGITs, and the DGITs have Wye-Ground:delta windings.**

Base impedance = $27.6kV^2$ / 1MVA = 762Ω,
Then the required Zero Sequence Reactance of the DG Facility is:
X_{DG0} = 0.6 x 762Ω ± 10% = 457.2Ω ± 10%
Assuming the reactance of each DGIT is 0.05p.u. on a 1 MVA base,
Then the required Zero Sequence Reactance of neutral reactor is:
$X_{0,NGR}$ = (457Ω – 0.05 x 762Ω) ± 10% = 419Ω ± 10%
Therefore, the size of neutral reactor for each DGIT is:
X_n = 419Ω / 3 ± 10% = 140Ω ± 10%

Example 4: **A 2MVA DG Facility is connected at 27.6kV, via a single 2MVA DGIT, and the DGIT has Wye-Ground:delta windings.**

Base impedance = $27.6kV^2$ / 2MVA = 381Ω,
Then the required Zero Sequence Reactance of the DG Facility is:
X_{DG0} = 0.6 x 381Ω ± 10% = 228.6Ω ± 10%
Assuming the reactance of the DGIT is 0.05p.u. on a 2 MVA base,
Then the required Zero Sequence Reactance of neutral reactor is:
$X_{0,NGR}$ = (229Ω – 0.05 x 381Ω) ± 10% = 210Ω ± 10%
Therefore, the size of neutral reactor for the DGIT is:
X_n = 210Ω / 3 ± 10% = 70Ω ± 10%

The continuous rating of the grounding devices shall be able to handle the maximum expected voltage unbalance with margin. As per Hydro One's Conditions of Service, the voltage unbalance on Hydro One feeders can reach 5%. Therefore, the grounding device should be sized for a minimum of 5% continuous voltage unbalance. The short time (5 sec) fault rating shall be sized for the maximum fault current that will flow through the grounding device for a close-in fault.

C.2 INTERCONNECTING TO HONI'S 3-WIRE DISTRIBUTION SYSTEM

For DG Facilities connecting to Hydro One's 3-wire Distribution System, neutral reactors are required to limit the fault current contributions from DG Facilities for ground faults on the interconnected feeder when the DGIT winding configuration is Wye-Ground:delta. Examples 5 and 6 are to provide the impedance calculations for neutral reactors that can be connected between the neutral of Wye-Ground:delta DGITs and the ground. As per Section 2.1.11 Grounding, for DG Facility with Conventional (Rotating) Generators, the Zero Sequence Reactance (X_{DG0}) should be greater than 8 times the Positive Sequence Reactance (X_{DG1}). For DG Facility with an Inverter Interface, the Zero Sequence Reactance (X_{DG0}) should be greater than 24 times the reactance of the DGIT.

Example 5: **A 10MVA Rotating Machine DG Facility is connected at 44kV, via a single 10MVA DGIT, and the DGIT has Wye-Ground:delta windings.**

Base impedance = $44kV^2$ / 10MVA = 193.6Ω,
Assuming the Positive Sequence Reactance of the DG Facility is:
$X_{DG1} = X''_d + X_t$ = 0.12p.u. + 0.05p.u. = 0.17p.u. on a 10MVA base,
Then the required Zero Sequence Reactance of the DG Facility is:
$X_{DG0} > 8 \times 0.17 \times 193.6\Omega = 263.3\Omega$
The required Zero Sequence Reactance of neutral reactor is:
$X_{0,NGR} > 263.3\Omega - 0.05 \times 193.6\Omega = 263.3\Omega – 9.7\Omega = 254\Omega$
Therefore, the size of neutral reactor should be greater than:
$X_n = 254\Omega / 3 = 85\Omega$

Example 6: **A 10MVA Inverter based DG Facility is connected at 44kV, via a single 10MVA DGIT, and the DGIT has Wye-Ground:delta windings.**

Base impedance = $44kV^2$ / 10MVA = 193.6Ω,
Assuming the reactance of the DGIT is 0.05p.u. on a 10MVA base,
Then the required Zero Sequence Reactance of the DG Facility is:
$X_{DG0} > 24 \times 0.05 \times 193.6\Omega = 232.3\Omega$
The required Zero Sequence Reactance of neutral reactor is:
$X_{0,NGR} > 232.3\Omega – 0.05 \times 193.6\Omega = 232.3\Omega - 9.7\Omega = 223\Omega$
Therefore, the size of neutral reactor should be greater than:
$X_n = 223\Omega / 3 = 74\Omega$

The continuous rating of the grounding devices shall be able to handle the maximum expected voltage unbalance with margin. As per Hydro One's Conditions of Service, the voltage unbalance on Hydro One feeders can reach 5%. Therefore, the grounding device should be sized for a minimum of 5% continuous voltage unbalance. The short time (5 sec) fault rating shall be sized for the maximum fault current that will flow through the grounding device for a close-in fault.

D APPENDIX D – ANTI-ISLANDING PROTECTION *(INFORMATIVE)*

The following is background information on Anti-Islanding Protection, its purpose, and some rational behind some requirements. Transfer Trip and Distributed Generator End Open is discussed. Also, a typical distribution system is shown and possible island formations are discussed. This information is provided as informational only. Requirements are listed in Section 2.3.12 and Section 2.3.13 of the TIR.

D.1 DG ISLANDING

A DG island is formed if a DG Facility remains connected to a portion of the Distribution System after that portion is separated from the normal Hydro One supply. DG islanding can expose Hydro One's Transmission and Distribution Systems and customers to unstable voltage and frequency and other adverse impacts. Most typically, DG islanding can occur when the feeder breaker or other isolating device at a TS or DS or along a radial-connected feeder is opened. Some of the causes that may lead to DG islanding are as follows:

[1] A fault that is detected and cleared by the utility before it can be detected and cleared by the DG Facility. Most DG islands will be established this way;

[2] Emergency switching of the Distribution System and loads;

[3] Equipment malfunction;

[4] Operating or human error; and

[5] Foreign interference or other acts of nature.

D.2 SUMMARY OF ADVERSE IMPACTS CAUSED BY DG ISLANDING

Potential adverse impacts of DG islands include but are not limited to following:

[1] Abnormal voltage and frequency excursions outside of the acceptable ranges because of DG Facility voltage regulation limitations;

[2] Excessive temporary overvoltage (TOV) can occur if DG Facility sources that are not effectively grounded back-feed single-line-ground faults;

[3] Extreme overvoltage from ferroresonance between the nonlinear magnetizing inductance of DGIT/induction generators and connected capacitance and system capacitance;

[4] Unpredictable DG energy sources that are not controlled by the utility. This includes generation sources and abnormal phase voltages caused by back-feed through multi-core three-phase DGITs in the presence of single-phase switching or other open circuit supply conditions;

[5] Failure to clear certain faults that cannot be detected by DG Facility self-clearing protections within required time;

[6] Interference with the restoration of normal supply from the utility;

[7] Asynchronous paralleling if DG Facility is present when Hydro One supply is restored.

D.3 RISKS

The risks associated with the adverse impacts include:

[1] Inadequate power quality - voltage and frequency;

[2] Damage - to customer and utility line equipment as a result of overvoltages or sustained or prolonged electrical faults where protections are insensitive or slow clearing;

[3] Prolonged customer outages resulting from failed automatic-reclosure or delays in establishing safe conditions for isolation and repair of damaged equipment;

[4] Safety hazards to public and utility workers since lines may be energized when it is assumed to be disconnected from all energy sources; and

[5] Increased liability and costs associated with all of the above.

These impacts must be avoided by maintaining adequate controls over the design and operation of the DG Facility connections. Transfer Trip (TT) and Distributed Generator End Open (DGEO) schemes are important tools that are required to avoid these adverse effects for certain configurations.

D.4 TYPES OF DG ISLANDS

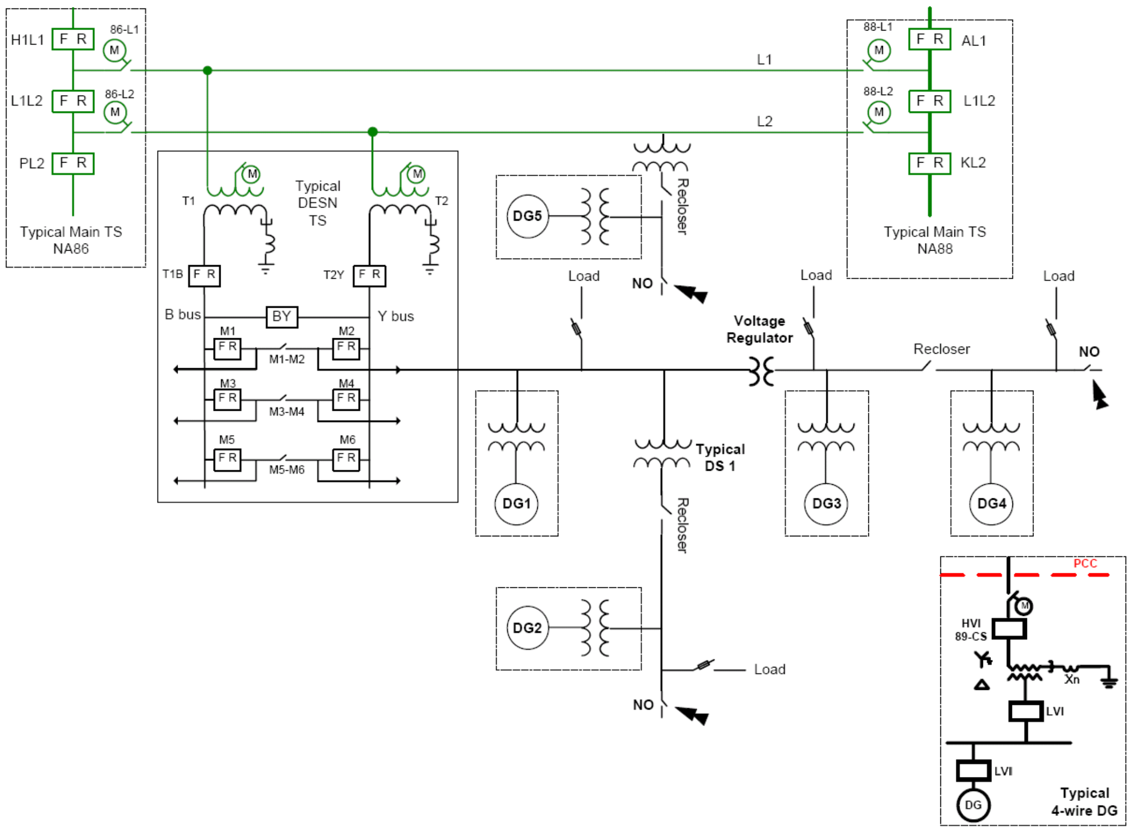


Figure 21: Typical Distribution System with DG Connections

DG Islands are formed whenever feeder reclosers or TS breakers are tripped from feeder or line protections interrupting the supply to a portion of the Transmission or Distribution System. The DG Facility must be removed from service before fuses are melted and before automatic reclosure takes place, to avoid interference with Hydro One restoration and asynchronous reclosure.

Appendix F includes graphs that show timing requirements for TT and DG Facility self-clearing protections, for various automatic-reclosure, fault detection and breaker times. For each DG island scenario, the aggregate capacity of the islanded DG Facility must be assessed in relation to the minimum connected islanded load.

Generally, if the islanded DG Facility aggregate capacity is greater than 50% of the minimum load of the connected island, then TT will be required to be sent from the most strategic Hydro One supply location(s) to disconnect the DG Facility to ensure successful automatic-reclosure operations.[43] The TT may be sent directly from the location of Hydro One's switching device to the DG Facility or a cascading arrangement may be used to redirect the TT to the DG Facility via another marshalling location (usually the TS).

RECLOSER DG ISLAND

i) A Recloser DG Island forms when a feeder recloser operates, interrupting the Hydro One supply to a section of a feeder to which the DG Facility is connected.

ii) In the example shown in Figure 21, DG2, DG4 and DG5 will be islanded by the adjacent Hydro One source-side reclosers opening.

iii) Typical automatic-reclose times for reclosers are 1.5 to 2 seconds.

FEEDER-BREAKER DG ISLAND

i) A Feeder-breaker DG island forms when feeder protection operates, opening a TS feeder-breaker and interrupting the Hydro One supply to the whole feeder to which the DG Facility is connected.

ii) In the example shown in Figure 21, DG1 - DG4 will be islanded by the opening of the M2 feeder breaker.

iii) Typical automatic-reclosure times for feeder-breakers are 0.5 to 1 seconds.

LV BUS DG ISLAND

i) An LV Bus DG island forms when a main terminal line protection operates for an HV line fault interrupting the Hydro One supply to a DESN TS LV bus to which the DG Facility is connected.

ii) In the example shown in Figure 21, an LV bus DG island would only occur if the bus-tie breaker BY was open and the L2 line protection opens LV transformer-breaker T2Y interrupting the Hydro One supply to the Y bus to which DG1 – DG4 are connected.

iii) Automatic-reclosure is initiated from the HV line protection and the LV transformer-breaker Transfer Trip or Remote Trip Receive protections. The typical automatic reclosure time for a DESN TS LV transformer-breaker is typically 1 second, but that will only be completed after the HV line protection at the main terminal TS automatically recloses, typically in 5 seconds (may be as low as 2 seconds).

[43] The significance of the 50% criteria is presented later in this Appendix.

DESN TS LV ISLAND

iv) A DESN TS LV island forms when one or more main terminal line protections operate for HV line faults, interrupting the Hydro One supply to a DESN TS to which the DG Facility is connected.

v) In the example shown in Figure 21, a DESN TS LV would occur if transformer breakers T1B and T2Y are both opened from operation of HV line protections, isolating all of the DG Facilities connected to the DESN TS (DG1 - DG4).

vi) Automatic-reclosure is initiated from the HV line protection and the LV transformer-breaker Transfer Trip or Remote Trip Receive protections. The typical automatic reclosure time for a DESN TS LV transformer-breaker is typically 1 second, but that only after the HV line protection at the main terminal TS automatically recloses, typically in 5 seconds (may be as low as 2 seconds).

WIDE-AREA DG ISLAND

i) A Wide-Area DG island can be formed when one or more main terminal line protections operate for HV line faults, interrupting the Hydro One supply to all DESN stations and to any HV-connected DS to which the DG Facility is connected.

ii) For a two-circuit supply, both circuits would have to be interrupted to cause a wide area DG island.

iii) In the example shown in Figure 21, a wide area DG island would occur if supply to both HV lines L1 and L2 are interrupted (a double circuit interruption). This is a relatively rare event but can happen during wind storms or other adverse conditions.

iv) For a single-circuit HV supply, operation of the line protection for that circuit would cause a Wide-Area DG island.

v) A Wide-Area DG island will occur if there is no TT from the main terminal station to the DESN station or HV-connected DS or that TT fails causing the DESN station LV breakers to remain closed. In that case, automatic-reclosure of the HV lines will restore Hydro One supply to all of the affected Wide-Area, typically in 5 seconds (may be as low as 2 seconds) provided that there is no back-fed voltage detected on the HV lines by the HV breaker automatic-reclosure schemes.

vi) A Wide-Area DG island may also occur if the next zone (upstream from Terminal Stations) is tripped. This may occur if the net generation in the wide area network can sustain the load at the time of occurrence.

D.5 DG ISLANDING NOT PERMITTED

At present DG islanding is not allowed due to the fact that DG Facility is neither responsible nor capable of maintaining the integrity of distribution system. Key points are shown below:

HYDRO ONE'S RESPONSIBILITY

Hydro One is responsible for the supply and voltage regulation of Hydro One's Distribution System and the maintenance of Distribution System voltages at acceptable levels as required by the OEB. Frequency is maintained very close to 60 Hz by the synchronized interconnection of Hydro One's Transmission System to the Eastern Interconnection of the North American Electric Reliability Corporation ("NERC"). Voltage and frequency will be maintained under normal system conditions as long as normal Hydro One supply remains connected to the Distribution System.

EXPECTED FREQUENCY AND VOLTAGE DEVIATIONS IN DG ISLANDS

When a DG island occurs, island voltages and frequency will depend entirely on the interaction between the islanded generation and load. Maintaining an island within acceptable limits would require at least one DG Facility in the island to actively regulate frequency and voltage to match changing island load demands. Furthermore the DG Facility capacity would have to be large enough to sustain the extreme range of load demands that may exist in the island. DG Facilities cannot meet these conditions for the following reasons:

i) Hydro One does not permit DG Facility voltage regulation systems to actively regulate voltage. This avoids mal-coordination of Distribution System voltage regulation and excessive operation of Hydro One's tap-changers and voltage regulators.

ii) Variable production conditions prevent DG Facility capacity from being capable of meeting the exact demands of any specific local loads or power transfers. As a result, DG island frequency and voltage can be expected to drift outside of the acceptable limits because of these inherent DG control and capacity limitations.

iii) The direction (over or under) of frequency and voltage change for a DG island will depend upon the relative mismatch of net real and reactive power between the islanded DG Facility and load. If the active power generation is less than the active power consumed by the load, the island frequency will drop. If the active power generation exceeds the active power consumed by the load, the island frequency will rise.

iv) Change in island voltage magnitude depends similarly on mismatch between distributed generation reactive power output and the reactive power demands of the islanded load.

v) The rate-of-change of frequency and voltage for a DG island will depend upon many factors. These factors include the amount of power unbalance, network impedances, voltage dependency of the feeder loads and dynamic characteristics of the islanded generation and loads (inertias of the interconnected machines and transient reactance).

vi) Even short duration DG islands may be too long to prevent adverse DG islanding impacts, unless specific design precautions are implemented.

POSSIBILITY OF EXTREME OVER-VOLTAGES AND BACK-FEEDS THROUGH TRANSFORMERS

i) Ferroresonance and single-line-ground faults can cause extreme or excessive over-voltages for some DG island configurations. These over-voltages are capable of causing damage to customer and Hydro One equipment.

ii) Back-feeds through multi-core three-phase DGITs in the presence of single-phase switching or other open circuit supply conditions. These voltages pose a safety hazard to public and utility workers for fallen conductors or when circuits are assumed to be dead but in fact are energized.

iii) These over-voltage and back-feed effects are largely dependent upon the size, grounding and magnetic-core characteristics of the DGIT connections. There are many ways to avoid or minimize these effects. That includes the following:

- Use of Transfer Trip;
- Use of a DG HVI to be tripped whenever an unbalanced condition is detected at the DG Facility location;
- Effective-grounding of the DGIT;
- Avoiding the use of multi-core transformers for three-phase connections in the presence of single phase switching upstream, by using three individual single-phase (single-core) DGIT connections; and
- Avoiding single-phase switching of three-phase transformers (where possible) or minimizing circuit capacitance from the DGIT to these locations.

D.6 AUTOMATIC-RECLOSURE

Transient faults on over-head line conductors caused by lightning, wind, tree branches falling, or other momentary foreign contact constitute approximately 85-90% of all faults.

Hydro One uses the standard utility practice of automatic-reclosure on distribution feeders with over-head line-sections to minimize supply interruptions for transient faults.

Automatic-reclosure is not generally used for feeders with extensive underground cable sections because cable faults are exposed to far fewer naturally occurring transient fault conditions. Also faults on cables are much more likely to be permanent requiring repairs.

D.7 BENEFITS OF AUTOMATIC-RECLOSURE

Automatic-reclosure has the following advantages:

i) It minimizes supply interruption to customers by automatically restoring the feeder to service as quickly as possible following transient faults.

ii) It minimizes damage at the fault and stress on equipment supplying the fault.

iii) It reduces operating costs. Less time and materials required to repair damage and restore service.

iv) It prevents blowing of fuses at tapped Distribution stations and lateral feeds resulting in all of the above.

D.8 HOW AUTOMATIC-RECLOSURE WORKS

i) For the first occurrence of the fault on any portion of the faulted feeder, high-speed sensitive low set protection operates quickly to de-energize the feeder.

ii) Following the first protection operation, the Hydro One feeder breaker or reclosers are automatically reclosed to restore supply to load customers as quickly as possible.

iii) Typical reclosing times are 0.5 to 1 second for feeder breakers and 1.5 to 2 seconds for reclosers.

iv) Reclosing time must allow for the fault to extinguish and de-ionize.

v) Reclosing time must also allow some time for the inertia and back emf of large motors to decay (to about 40% of normal voltage) and be disconnected by automatic controls.

D.9 AUTOMATIC-RECLOSURE REQUIRES DG TO DISCONNECT QUICKLY

Automatic-reclosure can succeed only if the fault arc is extinguished and de-ionized. Otherwise the fault is likely to re-strike after the feeder is re-energized.

i) If the DG Facility has not disconnected at the time that automatic-reclosure takes place, the automatic-reclosure would asynchronously re-parallel to all DG Facilities and any rotating motors that remained connected in the island.

ii) Extreme mechanical stresses associated with asynchronous paralleling could damage DG Facility generators, customer motors, switching equipment and any transformers that are connected in series between these energy sources.

iii) The potential impact of asynchronous connection of inverter-fed DG Facilities is less certain and will depend on their individual design. However since island voltage can be sustained by other generators and motors that remain connected, asynchronous reclosure must be avoided.

iv) For the above reasons, all DG Facilities must be quickly disconnected whenever a feeder fault is detected, before reclosure takes place.

D.10 LIMITATIONS OF DG SELF-CLEARING PROTECTION RESPONSE TIMES

i) Based on fault in-feed, DG Facilities cannot distinguish between faults on either side of the utility feeder breaker or recloser that supplies them. To avoid nuisance trips, some time delay is required by the DG Facility's interconnection protection to allow coordination with the faster utility protections to clear those out-of-zone faults. If that delay is too long, automatic-reclosure will be impaired.

ii) The DG Facility anti-islanding protection cannot prevent DG islanding. It can only detect an island after islanding occurs.

iii) All passive DG Facility anti-islanding detection methods rely on an unbalance or mismatch between distributed generation power output and power demands of the connected load on the isolated island. DG island frequency and voltage can be expected to drift, as outlined above.

iv) Close matching of both active and reactive power would be an extremely unlikely condition for a prolonged period. Sooner or later, mismatches will cause the voltage or frequency to drift outside the protection limits specified in Sections 2.3.

v) If by chance the active and reactive power produced by islanded DG Facility happens to be close to the islanded load demand, then the island may survive for a longer period before DG Facility self-clearing protections will detect and disconnect the generation.

vi) In some cases, DG Facility self-clearing anti-islanding protections cannot be relied on to guarantee that the DG Facility will disconnect itself before automatic-reclosure takes place. In those cases, TT and DGEO schemes are required. Refer to appropriate sections for requirement conditions.

D.11 MAXIMUM DETECTION TIMES AVAILABLE FOR DG SELF-CLEARING PROTECTIONS

AUTOMATIC-RECLOSURE CONSIDERATION

There are limited time windows available following the formation of an island during which time DG self-clearing protections have to disconnect the generator before automatic-reclosure takes place.

i) If there is a fault on the feeder at the time the DG island is formed, the DG Facility fault protection must detect the fault and initiate clearance.

ii) If there is no fault on the feeder at the time the DG island is formed, the DG Facility's anti-islanding protection must detect the island condition and disconnect the generation from the Distribution System.

Timing diagrams and graphs for self-clearing DG Facility's interconnection protection are shown in Appendix F.

The times are based on the following assumptions and constraints:

i) The Hydro One automatic-reclosure timer is initiated without delay, immediately after the fault is detected by the Hydro One feeder protection.

ii) The assumed maximum Hydro One fault clearance time is 83ms after the fault is detected (5-cycle breaker opening time for oil dead-tank breakers).

iii) 200ms fault extinction and de-ionization time and/or drop out of motor controls is required after the last source trips, prior to reclosure.

iv) The graph shows the effect of DG Facility interrupter times on available Fault detection and Island detection times to avoid interference with Automatic-Reclosure.

For example, to prevent interference with automatic-reclosure (1 second reclosure), a DG Facility with a 5-cycle interrupter would require:

i) Self-clearing DG Facility anti-islanding protections capable of island detection within 633ms.

ii) DG Facility fault protection must be capable of detecting all three-phase and phase-ground faults to the extreme ends of the supply feeder within 717ms.

iii) For reclosure times longer than 1 second, the protection response times can be lengthened by equivalent amounts.

TT will be required to speed up DG Facility clearance if the above conditions cannot be met.

To prevent interference with automatic-reclosure with a reclose time of 500ms:

i) Self-clearing DG Facility anti-islanding protections capable of detecting an island condition within 133ms.

ii) DG Facility fault protections must be capable of detecting all three-phase and phase-ground faults to the extreme ends of the supply feeder within 217ms.

iii) It is expected that DG Facility self-clearing protections cannot selectively and reliably detect fault and island conditions in such a short time. TT and DGEO will always be required to speed up DG clearance where 0.5-second reclosure times are used.

FUSE SAVING CONSIDERATIONS

Slow-clearing DG Facility in-feeds to faults can cause Distribution System fuses to melt can cause prolonged customer outages resulting from melted fuses. To reduce this all DG Facility shall be disconnected within 200ms of when external faults are detected on the Distribution System.

D.12 TRANSIENT RESPONSE OF DG ISLANDS (THE BASIS OF THE "50% RULE")

i) Hydro One's transient stability studies for some typical synchronous generators have demonstrated some consistent effects that various generation-to-feeder load ratios have on DG Facility voltage and speed (frequency).

ii) These studies have shown that for 50% generator rating to feeder load ratios, generator frequency declined steadily to about 53Hz within 1 second. Voltage declined rapidly to about 75% within about 100ms and recovered somewhat to about 93% within 1 second.

iii) Such frequency excursion to 53Hz should ensure that the under-frequency protections set as per Section 2.3.10 will clear in much less than 1 second (160ms for frequency < 57 Hz).

iv) Such voltage excursion to 75% may take up to 2 seconds to clear for protection set as per Section 2.3.11 (2 seconds for 50 ≤ V < 88%).

v) For higher generator rating to feeder load ratios, frequency and voltage does not drift outside the limits specified in Sections 2.2.2.5 and Section 2.2.2.1.

vi) Generic models for other types of generators - self-fed induction (“SFIG”), Double-fed Asynchronous (“DFAG”), inverters and static power converters are not sufficiently available to guarantee that DG Facility anti-islanding protections will operate in sufficient time for all conditions to prevent interference with automatic-reclosure.

vii) Based on the above, Hydro One has established a 50% active power unbalance threshold (DG Facility aggregate capacity / minimum load) above which TT is required to be used to avoid interference with Distribution System automatic-reclosure schemes.

viii) This only applies where automatic-reclosure time is 1-second or longer.

D.13 TRANSFER TRIP PROVIDES PREDICTABLE ANTI-ISLANDING PROTECTION CLEARANCE TIMES

Transfer Trip (TT) application provides predictable DG Facility clearance times and is the only protection which can guarantee anti-islanding. Distributed Generator End Open (DGEO) is always used with TT to guarantee disconnection of DG Facility before the feeder is re-energized or the breaker is re-closed. Thus, TT, DGEO and Re-closing shall be discussed.

There is no direct relation of Low Set Block Signal (LSBS) with anti-islanding protection, but this signal can utilize the same channel which is to be utilized by DGEO. Thus LSBS shall also be discussed briefly.

TRANSFER TRIP APPLICATION

Transfer Trip (TT) is a protection trip signal that is sent from the Hydro One supply source breaker or recloser to the DG Facility when the DG Facility is required to be disconnected. Transfer Trip (TT) is often required to mitigate the adverse impacts of DG Facility connection and islanding.

TT TIMING REQUIREMENTS

Refer to Section 2.3.13 and Appendix F for TT timing requirements.

D.14 DISTRIBUTED GENERATOR END OPEN (DGEO)

DGEO is a real time signal that is continuously sent from the DG Facility to Hydro One's supply source breaker or recloser. It establishes the connection status of the generation equipment.

i) For ungrounded 3-wire connections, where the DG Facility source cannot contribute ground fault current, the DGEO signal is derived from all breakers/circuit switchers at the interface between the DG Facility generation and the PCC necessary to establish DG Facility generation connectivity. It establishes the connection status of the generation equipment and is used to block automatic-reclosure should DG Facility fail to disconnect after the Hydro One supply is disconnected. For 3-wire connections that do not have an HVI, connectivity of the generators will be established by LVI connection logic that mimics all of the possible generation connection paths.

ii) For 4-wire connections, the DGEO signal must be derived from the DG Facility HVI switch only. For 4-wire connections all DG Facility ground sources must be connected to the DG Facility side of the HVI switch and must be disconnected before Hydro One source can be permitted to energize the feeder. That is because any fault that occurs immediately following Hydro One energization of the feeder is almost certain to be permanent, and Hydro One low-set fuse-saving protections are blocked. This allows coordinated clearance of the down-stream reclosers and fuses with the Hydro One source timed protections.

DGEO requirements are specified in Section 2.3.14. Design recommendations are included in Appendix E.

D.15 APPLICATION OF TT AND DGEO "50% RULE" REQUIREMENTS TO DG ISLANDS

The 50% TT rule is intended to preserve the benefits of automatic-reclosure following transient line fault conditions, by ensuring DG Facilities do not interfere with the successful operation of automatic-reclosure schemes.

Automatic-reclosure is not initiated for other types of permanent faults – recurring line faults, transformer faults, bus faults or breaker failure condition. In these cases, providing other adverse impacts are minimal for short-duration DG islanding, self-clearing anti-islanding protections (over/under voltage and over/under frequency) may be sufficient to disconnect the generation from the island when frequency and voltage transcend the limits specified in Sections 2.2.2.5 and 2.2.2.1 respectively. In all cases, high reliability is required for all protection schemes that are required to maintain the integrity of Hydro One's Distribution System.

Typical DG islands that can be formed during transient fault conditions are illustrated in Figure 21 and discussed earlier under "Types of DG islanding".

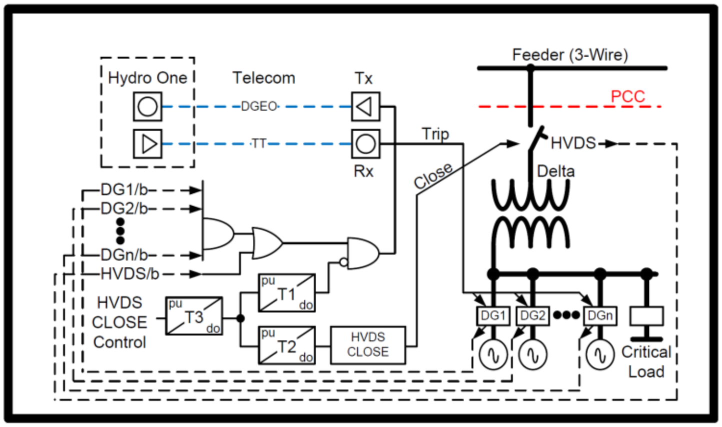
D.16 LOW SET BLOCK SIGNAL (LSBS)

i) Low Set Block Signal (LSBS) is a signal that is sent from the DG Facility to the Hydro One supply source breaker or recloser, whenever a large DGIT is being energized. Detection of this signal transition at the Hydro One supply source breaker or recloser location will cause the most sensitive low-set (fuse-saving) protection to be temporarily blocked. This will prevent the tripping of the Hydro One supply source during the period when there is large energizing inrush current due to the DGIT. Refer to Appendix E for more information regarding the LSBS signal.

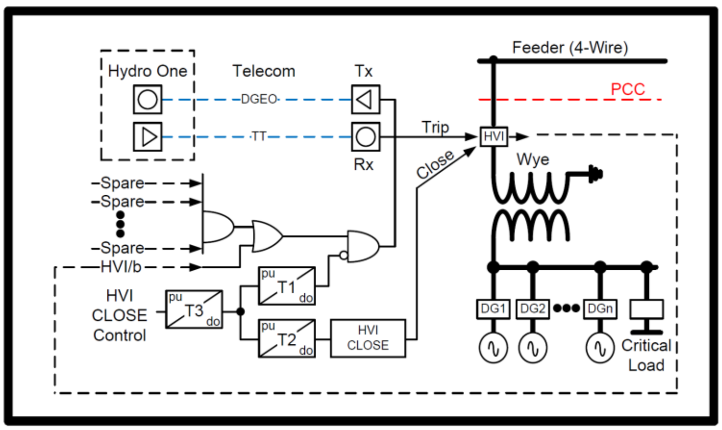
ii) Because the momentary LSBS signal will always be sent just prior to reconnection (near the end of the DGEO open condition), both DGEO and the LSBS functions shall be combined as one signal through a communication channel from the DG Facility to the Hydro One source energizing location(s).

E APPENDIX E – DGEO & LSBS DESIGN CONSIDERATION *(INFORMATIVE)*

The following information is a design consideration for Section 2.3.16 (DGEO and LSBS Design Requirement). It is an example of how the signals can be implemented for installations utilizing a High Voltage Interrupter or a High Voltage Disconnect Switch (motorized Isolation Device – See Section 2.1.7). This is for informational purposes only and actual design and implementation may be different.



HVDS on 3-Wire



HVI on 4-Wire

*HVDS - High Voltage Disconnect Switch

Based on Blocking the Low Set Inst at Hydro One for 5 seconds on a falling edge DGEO signal transition

Example #	Teleprotection Delay		HVI	HVDS	Timer T1		Timer T2		Timer T3	
	TT Delay	DGEO Delay	Close Time	Close Time	PU Delay	DO Delay	PU Delay	DO Delay	PU Delay	DO Delay
1	16ms	16ms	100ms		0ms	0ms	1s	0ms	0ms	6s
2	16ms	16ms		1s	0ms	0ms	1s	0ms	0ms	6s
3	30ms	250ms	100ms		0ms	0ms	1s	0ms	0ms	6s
4	30ms	250ms		1s	0ms	0ms	1s	0ms	0ms	6s

Figure 22: DGEO & LSBS Design Consideration

F APPENDIX F – TIMING DIAGRAMS *(INFORMATIVE)*

The following are a few sample timing diagrams for informational purposes. These have been created to represent a realistic sequence of events and the associated timings for different fault clearing and anti-islanding applications. These times may change due to site specific requirements and thus, timing requirements shall be confirmed with Hydro One for specific DG Facility projects.

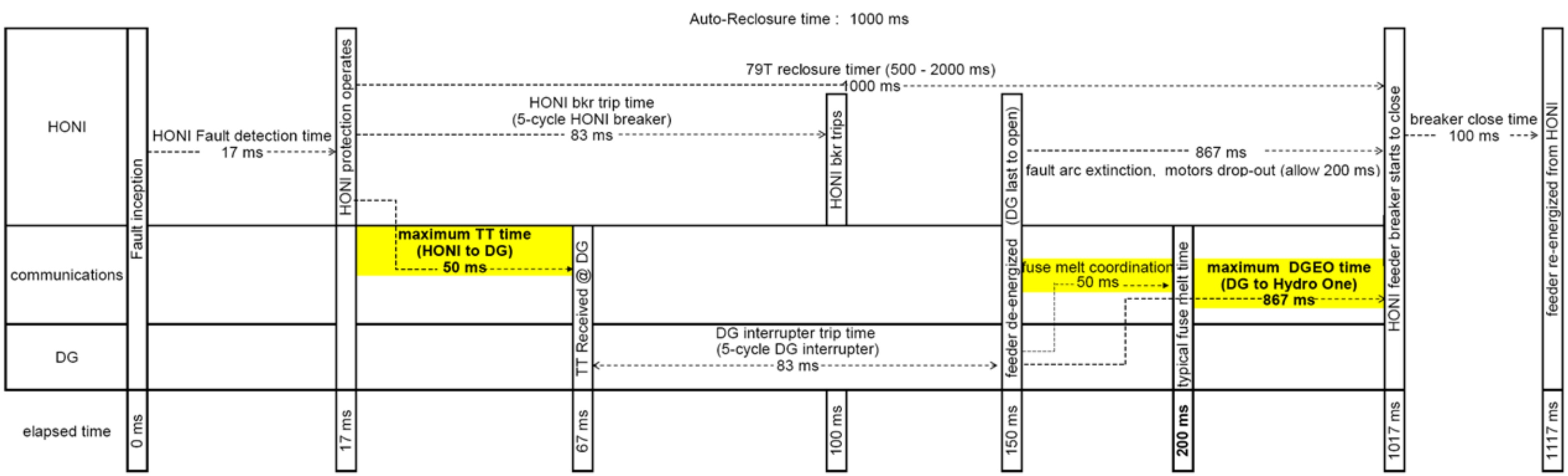


Figure 23: Typical Transfer Trip timing

Figure 23 illustrates typical trip/reclose timing for a feeder fault detected by a Hydro One feeder low-set protection. The Hydro One supply is isolated by a 5-cycle Hydro One breaker and Transfer Trip to the DG Facility. If the DG Facility interrupter opens in 5 cycles, a 50ms end-to-end TT transfer trip time is required to clear DG Facility infeed to the fault within 150ms.

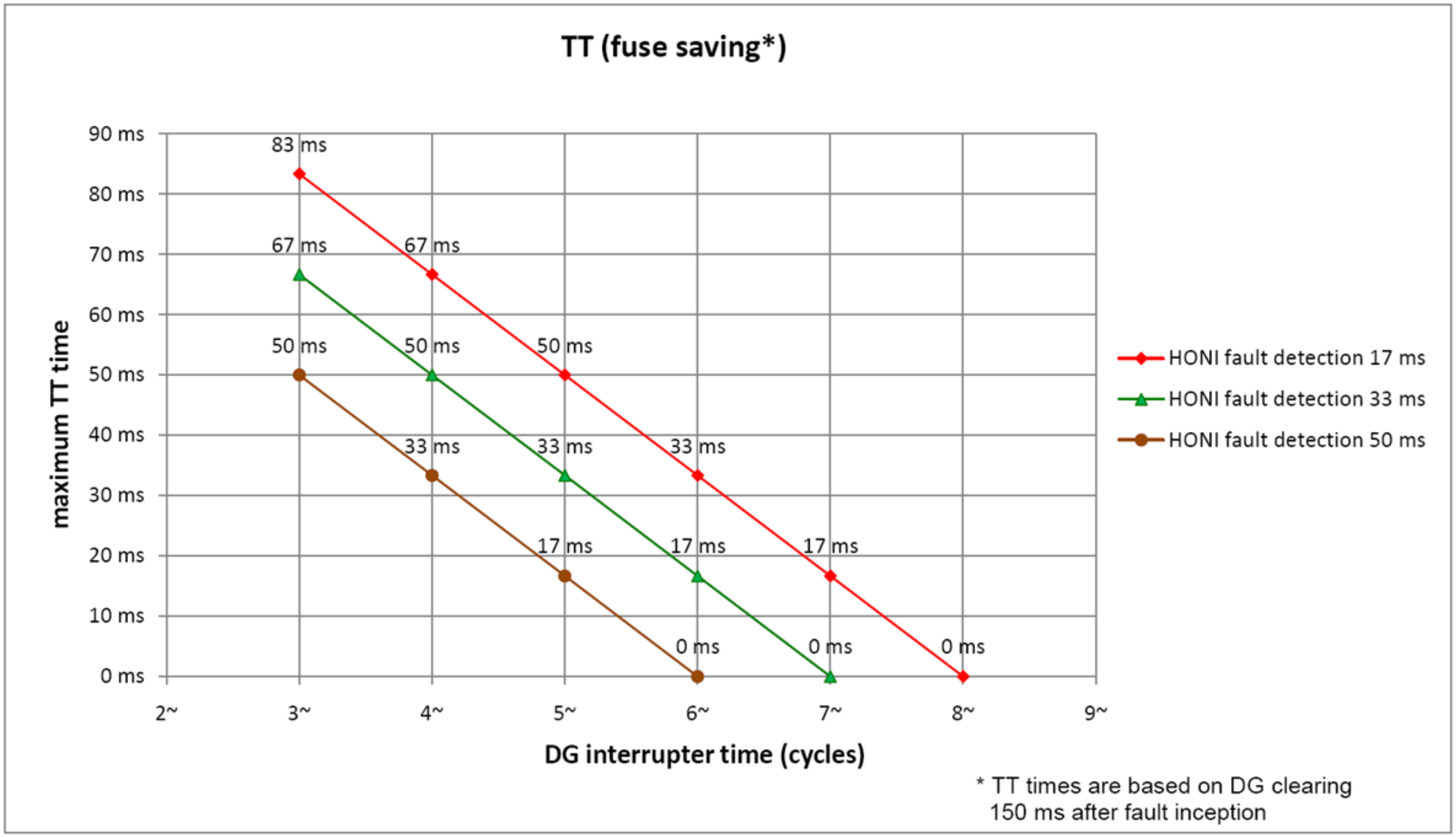


Figure 24: Relationship between timing variables for DG self-clearing

Figure 24 illustrates the end-to-end TT timing requirements to clear the DG Facilities infeed to a fault within 150ms, for various DG Facility interrupting devices operating times. The three curves show how various Hydro One fault detection times would affect the required TT times. Hydro One instantaneous low-set protections will typically detect the fault within 17ms, so the red curve will normally apply.

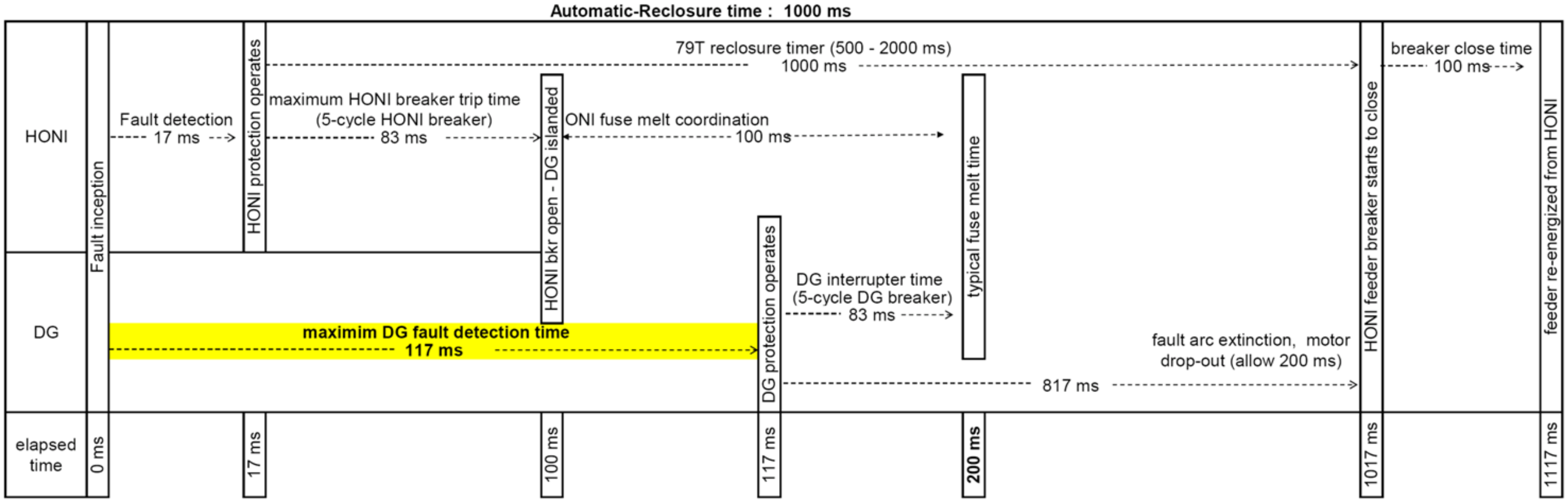


Figure 25: Typical DG self-clearing fault clearance (Fuse Saving considerations)

Figure 25 illustrates trip/reclose timing for typical feeder fault detected by a self-clearing DG Facility's interconnection protection with a 5-cycle interrupter. In order to clear the DG Facility infeed to the fault within 200ms to avoid fuse melting, the DG Facility fault detection protection needs to operate within 117ms.

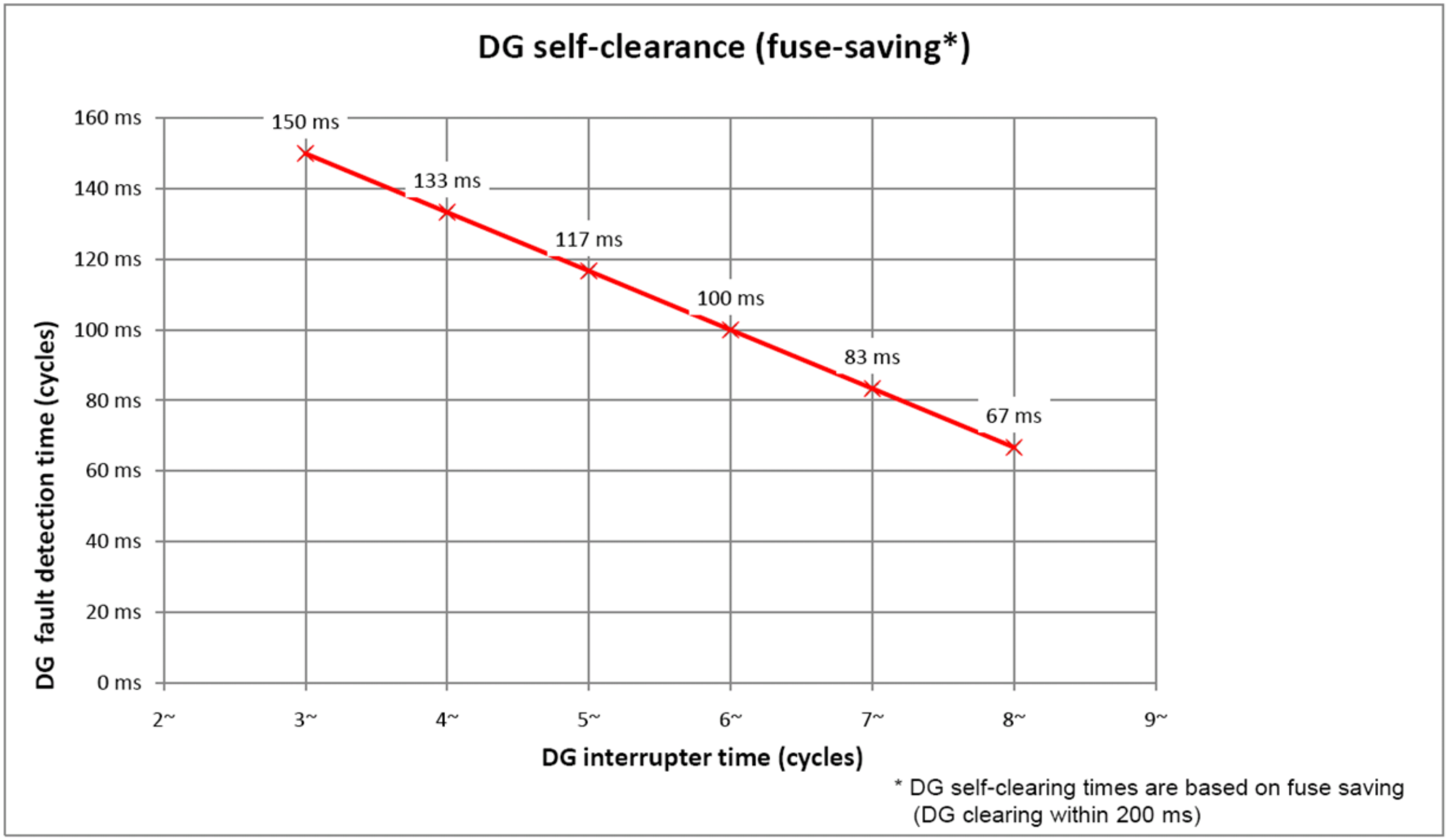


Figure 26: Relationship between DG self-clearing protection and interrupter times (fuse saving considerations)

Figure 26 illustrates the timing requirements for DG Facility's external fault detecting protections to clear the DG Facility infeed to the fault within 150ms, for various DG Facility interrupting device operating times.

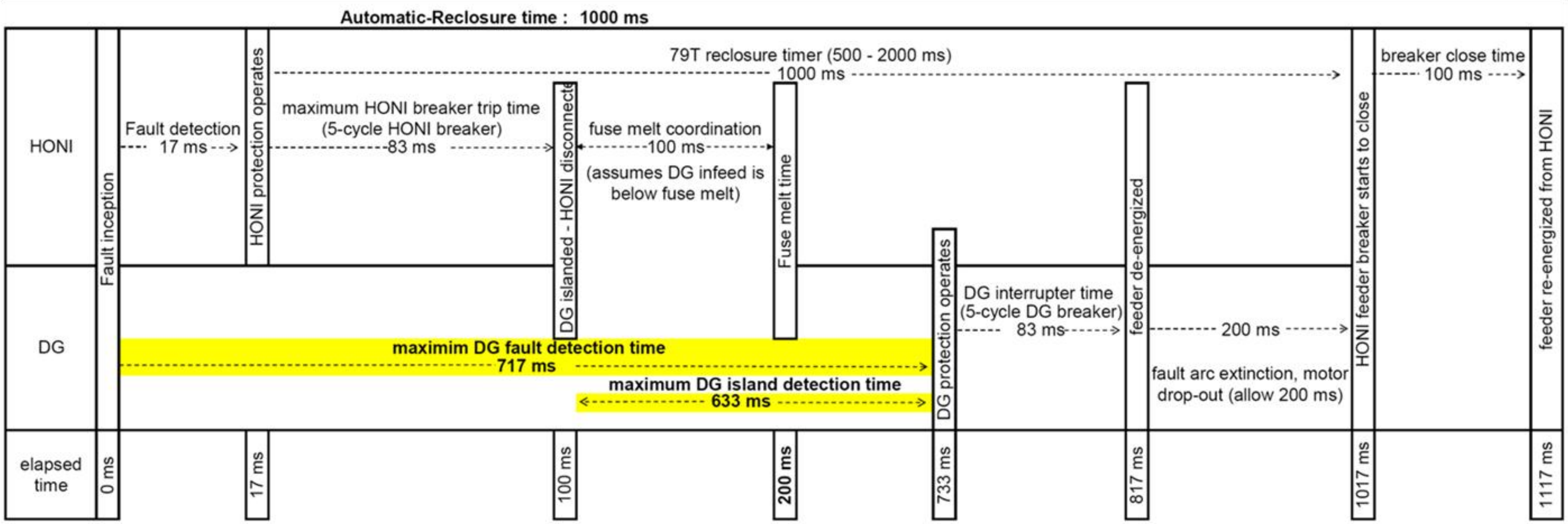


Figure 27: Typical DG self-clearing fault clearance (Auto-Reclosure timing considerations)

Figure 27 illustrates trip/reclose timing for a typical feeder fault detected by a self-clearing DG Facility's interconnection protection with a 5-cycle interrupter. In order to avoid interference with a 1-second Auto-Reclosing sequence, the DG Facility's external fault detecting protections needs to operate within 717ms. If there is no fault, the DG Facility's anti-islanding protection needs to detect faults within 633ms.

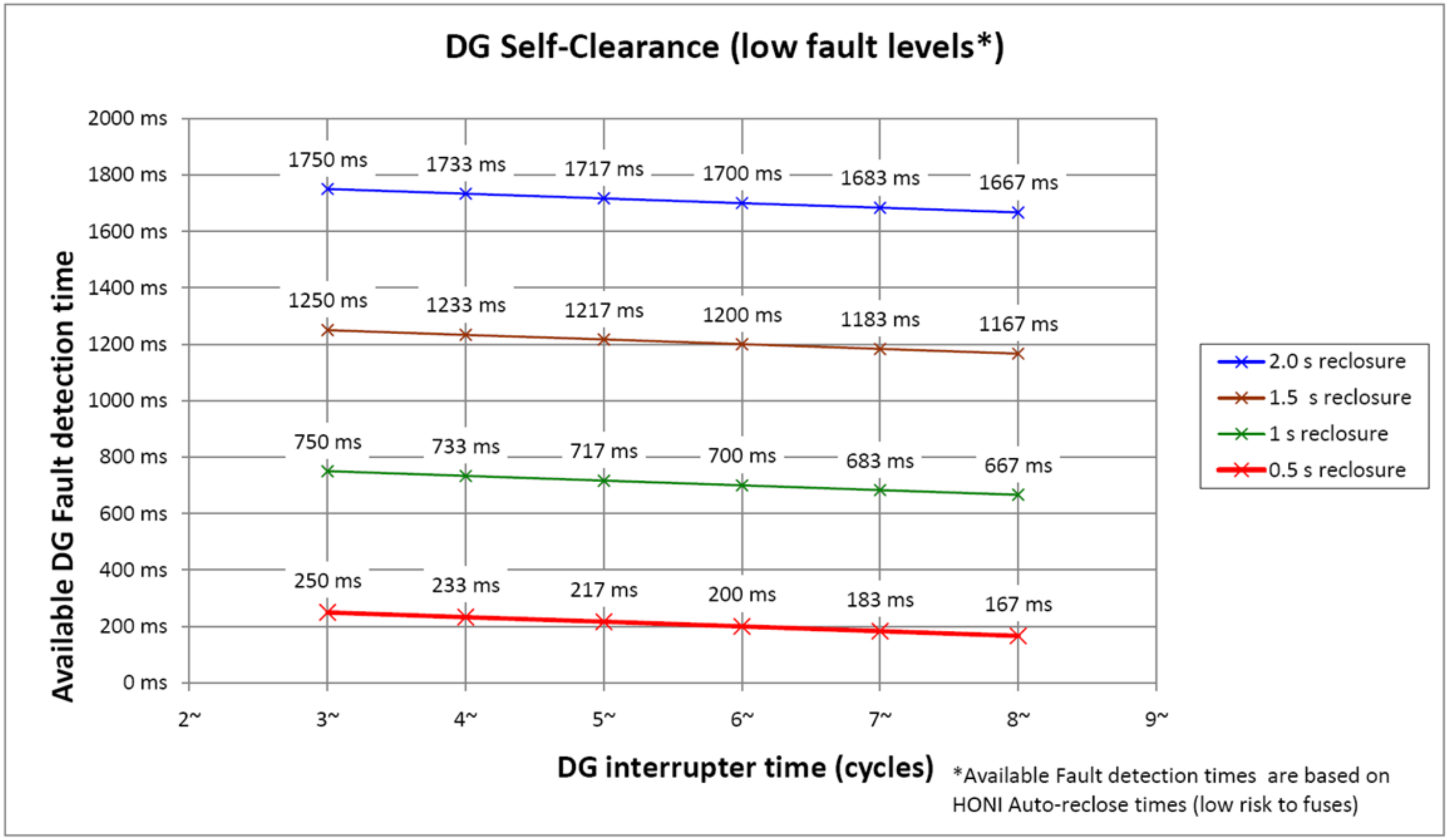


Figure 28: Relationship between DG self-clearing protection and breaker times (Auto-Reclosure timing considerations)

Figure 28 illustrates timing requirements for DG Facility's self-clearing interconnection protection to detect external feeder faults for various DG Facility fault interrupter times, in order to avoid interference with various Auto-Reclosure times.

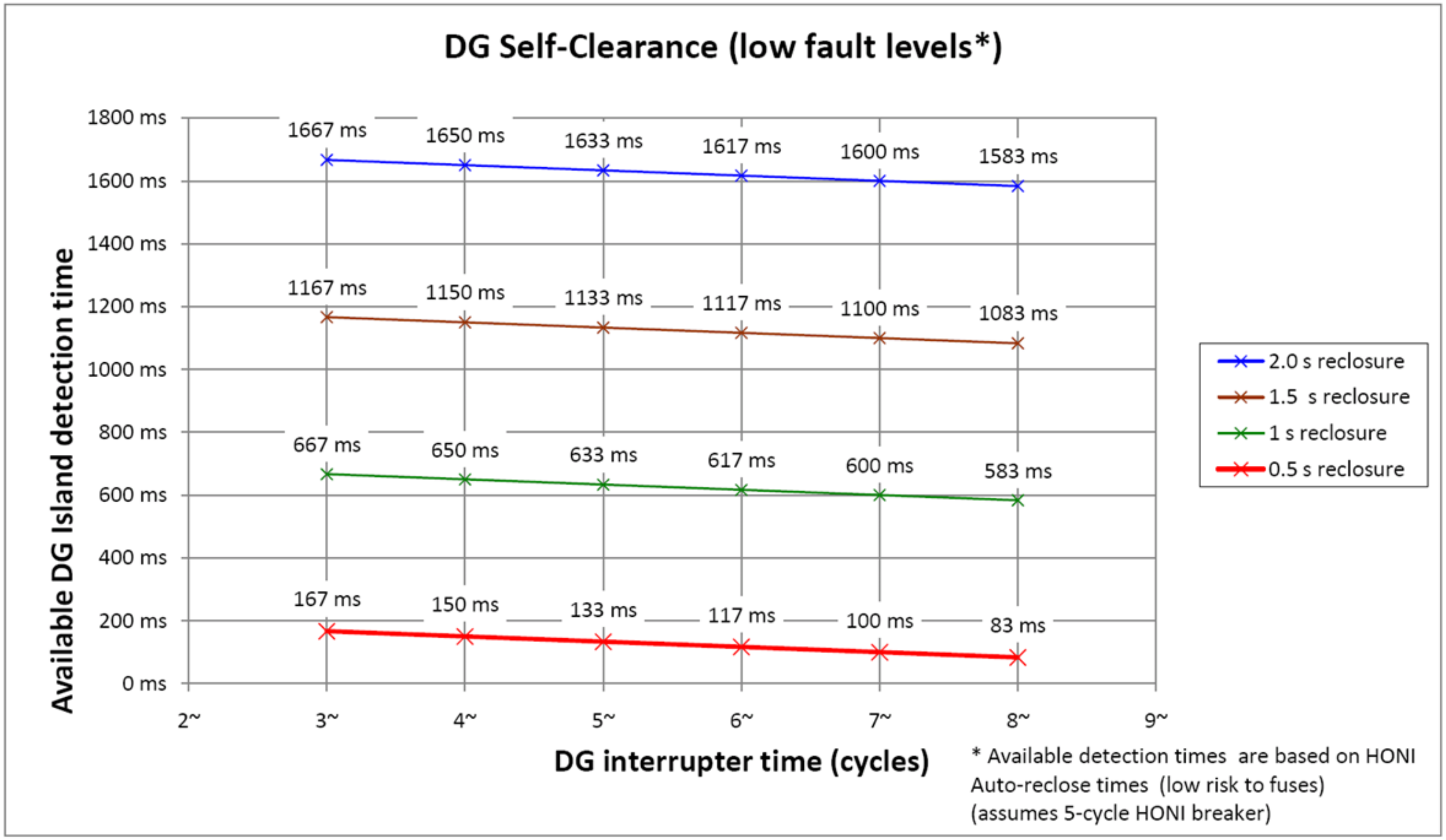


Figure 29: Relationship between DG island detection and breaker times (Auto-Reclosure timing considerations)

Figure 29 illustrates the timing requirements for DG Facility's self-clearing interconnection protection to detect island conditions for various DG Facility fault interrupter times, in order to avoid interference with various Auto-Reclosure times.

G APPENDIX G – SEQUENCE OF EVENTS DURING FAULT CONDITIONS: EXAMPLE (*INFORMATIVE)*

The following two figures are a typical sequence of events during abnormal conditions, for both a transient fault and a permanent fault. Note: These diagrams assume that the DG Facility requires Transfer Trip and an HVI. This is for informational purposes only. Note: Viewing may be easier if viewed on computer and zoomed in.

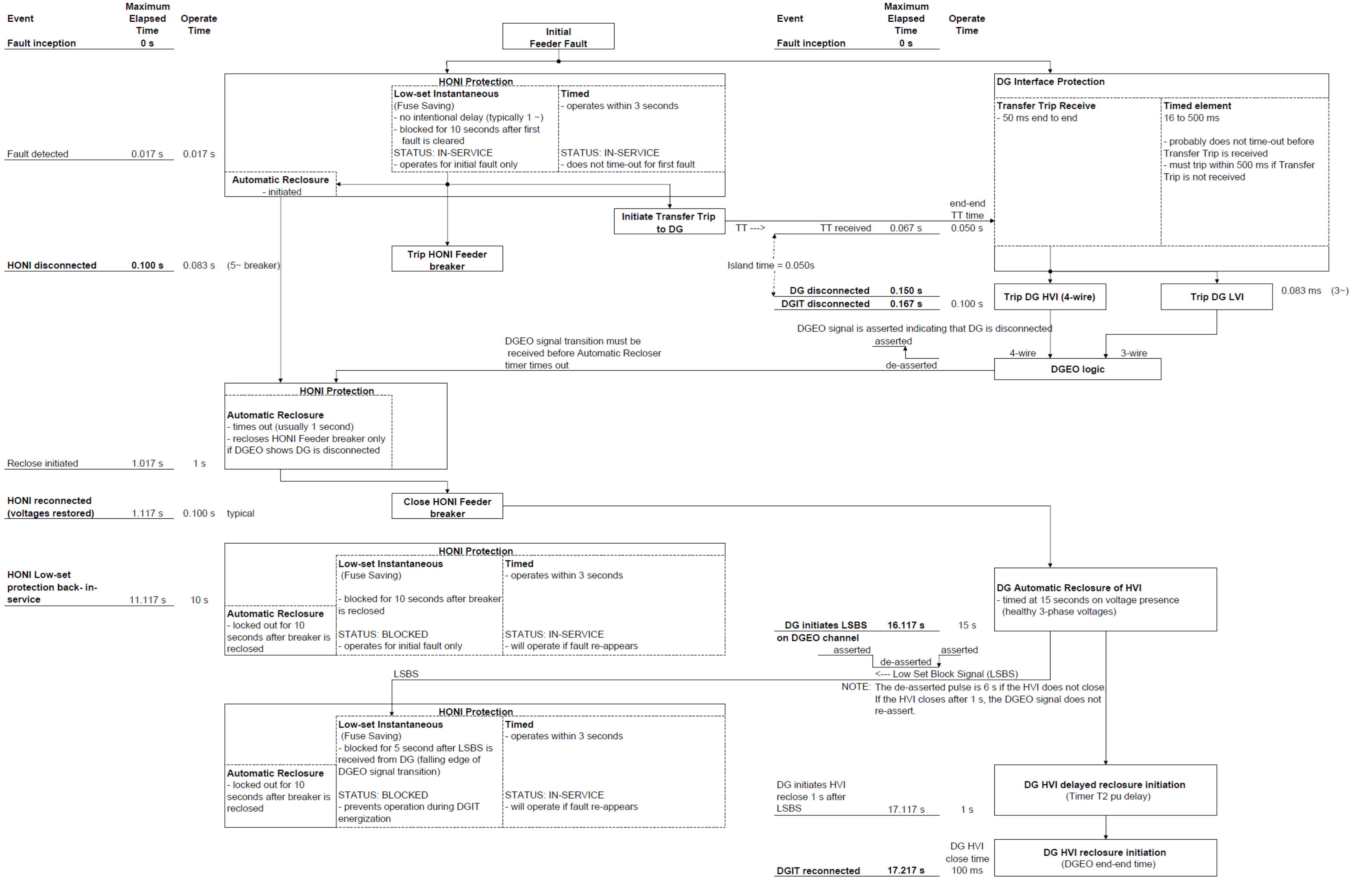


Figure 30: Sequence and Timing Diagram for Transient Faults

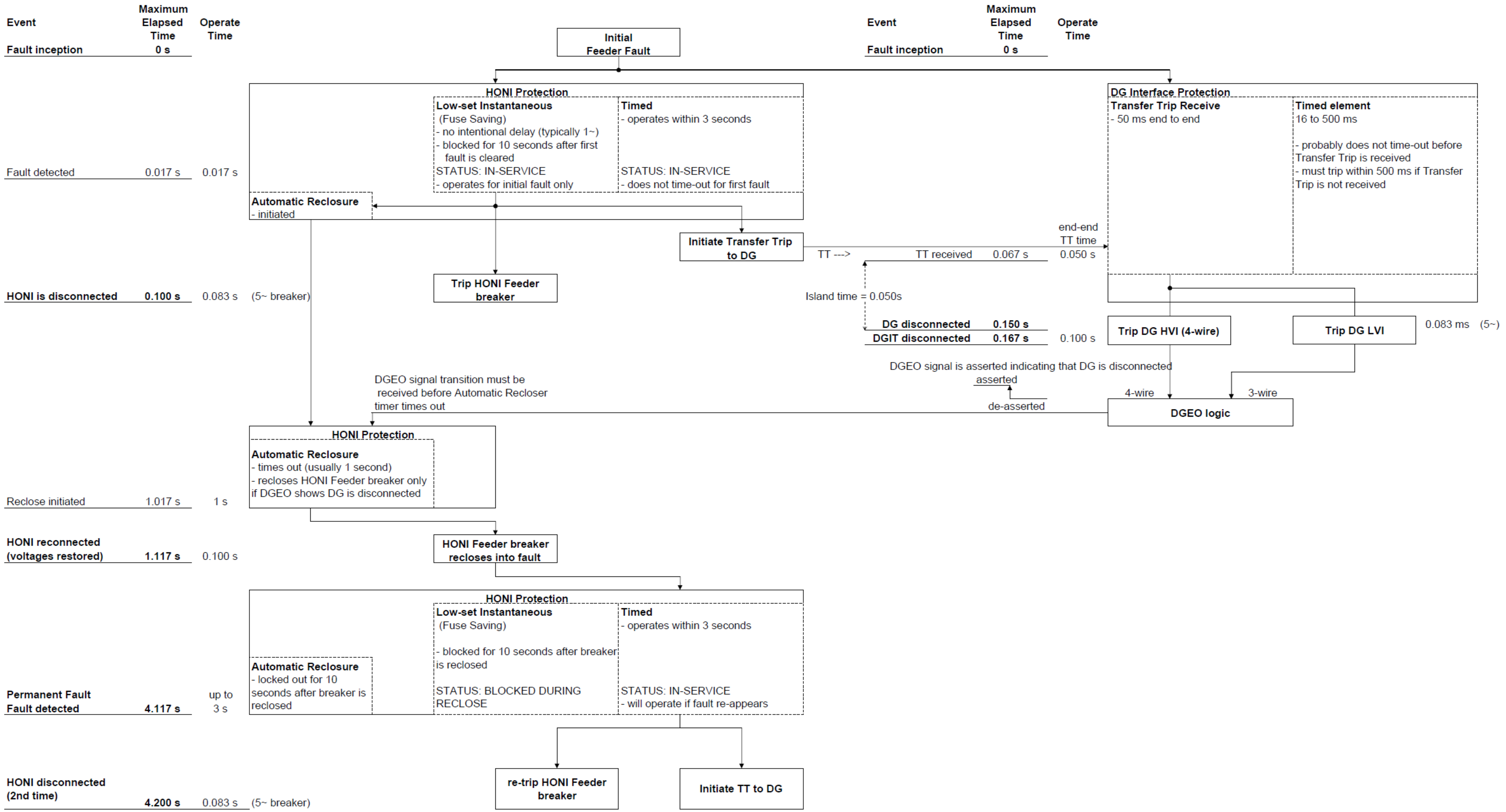


Figure 31: Sequence and Timing Diagram for Permanent Fault

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