SYNERGY NORTH Parallel Generation Requirements

Revision List

Rev #	Date	Changes By	Comments
8	Oct 9, 2019	Dan Dillon, P. Eng	Remove “traceable” requirement Update provisions for monitoring
7	Jan 15, 2019	Dan Dillon, P. Eng	Updated to SYNERGY NORTH
6	Oct 9, 2013	Joe McVety, P.Eng	Volt/Freq. to match IEEE1547
5	May 15, 2013	Joe McVety, P.Eng	Net Metering, Title to match COS
4	Nov 11, 2012	Joe McVety, P.Eng	Addition of Metering Information
3	July 31, 2012	Joe McVety, P.Eng	Minor format corrections.
2	July 14, 2011	Joe McVety, P.Eng	Voltage Regulation, Maintenance,
1	June 1, 2011	Joe McVety, P.Eng	Revised Formatting
0	Nov 27, 2009	Matthew Denis, EIT	Initial Release

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SYNERGY NORTH ‘Technical Requirements for Generators’ identifies minimum requirements for generation projects connecting to SYNERGY NORTH’s distribution system. 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 Distributed Generator Requirements 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 this document and the information it contains is at the user’s sole risk. SYNERGY NORTH, nor any person employed on its behalf, makes no warranties or representations of any kind with respect to the DG Requirements, including, without limitation, its quality, accuracy, completeness or fitness for any particular purpose, and SYNERGY NORTH will not be liable for any loss or damage arising from the use of this document, any conclusions a user derives from the information in this document or any reliance by the user on the information it contains. SYNERGY NORTH reserves the right to amend any of the requirements at any time. Any person wishing to make a decision based on the content of this document should consult with SYNERGY NORTH prior to making any such decision.

Introduction

These technical requirements for Distributed Generation ("DG") are to ensure public and employee safety, to protect the integrity of SYNERGY NORTH's system, and to guarantee reliable and quality service to SYNERGY NORTH customers. The technical requirements in this document are for the protection of SYNERGY NORTH's facilities, and the DG should satisfy itself as to any requirements for the protection of its own facilities.

The requirements below are primarily from Appendix F.2 of the Distribution System Code's ("DSC"), Institute of Electrical and Electronics Engineers ("IEEE") Standard 1547, and CAN/CSA C22.2 No. 257-06. DG developers are encouraged to consult the listed references for more details.

1) Point of Disconnection –

a) Safety

A point of disconnection is required to isolate the DG for the purpose of work protection for SYNERGY NORTH crews. Switching, lockout and tagging procedures shall be coordinated with SYNERGY NORTH.

The disconnect or isolation device must be

• Readily accessible by SYNERGY NORTH

• Lockable

• Gang operated

• Visible open point

• Located between the PCC and the DG, within 2m and visible to the meter

• Have visible warning signs that inside parts can be energized when the switch is open

• Labeled as "WARNING – TWO POWER SOURCES"

An additional point of disconnection (similar to the above) between the PCC and the meter is recommended in order to minimize outages to the load service during generator related work

Reference codes and standards that apply to the disconnect or isolation device are as follows: Ontario Electrical Safety Code ("OESC") rule 84-026, IEEE Standard 1547 Clause 4.1.7, CAN/CSA-C22.2 No. 257-06 Clause 5.3.4 and DSC Appendix F.2 Section 1.

b) Metering

Metering equipment including base, cabinet, instrument transformers / primary metering unit (PMU), and the meter unit itself, is specified explicitly by SYNERGY NORTH. The generation customer is responsible to purchase and installs meter base, CSTE cabinet, and/or PMU, based on SYNERGY NORTH approved shop drawings. SYNERGY NORTH performs the instrument transformer (IT) terminations and meter installation.

c) Parallel connections

- Where installation of generation is into or onto a building with existing General Service (Under 50kW), the meter configuration will be required as dual meter base if generation rate is different from load rate (microFIT program), and single meter base where the rates are equal (Net Metering program), and is subject to all requirements under SYNERGY NORTH's Conditions of Service.

- Where installation of generation is into or onto a building with existing General Service (50kW to 5000kW), and the service type is "secondary" – not requiring SYNERGY NORTH owned transformation facilities on customer owned property; the meter configuration will be required as dual meter base, and is subject to all requirements under SYNERGY NORTH's Conditions of Service.
- Where installation of generation is into or onto a building with existing General Service (50kW to 5000kW), and the service type is "primary" - requiring SYNERGY NORTH owned transformation facilities on customer owned property), the meter configuration will be negotiated and decided by SYNERGY NORTH based on
    - Available space near existing facilities
    - Potential safety hazards
    - Accessibility
- Where installation of generation is into or onto a building with existing General Service (5000kW and up), meter configuration will be determined on a case by case basis.

Reference codes and standards that apply to the metering configuration for parallel connections are as follows: SYNERGY NORTH Conditions of Service.

2) Preferred Interface Transformer Config. and HV Interrupting Device

The table below lists the configuration that will normally be required by SYNERGY NORTH for the DG facility interface transformer. The interface transformer connection significantly affects the DG interaction with SYNERGY NORTH's distribution system under steady state and fault conditions therefore the specification is critical to avoid adverse effects.

Selecting an appropriate configuration is dependent on the local distribution system at the point of connection. The configurations suggested are applicable for the majority of connections. SYNERGY NORTH will assess each connection individually to determine the required configuration based on the local conditions. In some situations a DG neutral impedance or grounding transformer may be required. Effective grounding criteria of the distribution system must be maintained so that the maximum overvoltage on the distribution system under fault conditions is less than 125% of the nominal steady state voltage. The HV interrupting device should be a breaker capable of withstanding 220% of the interconnection system rated voltage in accordance with IEEE Standard 1547, Section 4.1.8.3.

DG Rating	Distribution System Grounding Impedance (Low, High*)	Interface Transformer Configuration (HV:LV)
> 1 MW	Low	Wye Ground / Delta
> 1 MW	High	Delta / Wye Ground
< 1 MW	Low	Wye Ground / Wye Ground

* Low impedance grounding is where effective multi-point grounding can be achieved. High impedance grounding is where effective multi-point grounding cannot be achieved.

Reference: IEEE Standard 1547 Clause 4.1.8.3, DSC Appendix F.2 Section 2, SYNERGY NORTH Requirement

3) Equipment Rating and Requirements Reference

The generation facility interface equipment shall be compatible with SYNERGY NORTH equipment design and ratings under all operating conditions.

Equipment ratings to be reviewed, but are not limited to, are:

a) Equipment **thermal loading limits.** This equipment includes feeder conductor/cable, station breaker and transformer ratings.

b) Impact of generation facility **fault contribution** on equipment rating - If power is to be exported to the distribution system then all **metering devices** shall be suitable for **bi-directional flow**.

Reference: DSC Appendix F.2 Section 5

4) Voltage Regulation Reference

Voltage variations at the point of common coupling ("PCC") are limited to +/- 6% of the nominal voltage.

The generation facility should not actively regulate the voltage at the PCC. Voltage at the PCC shall be maintained within acceptable limits by operating at a power factor specified by the Distributor (see Section 8).

During normal operation, the generation facilities, particularly multiple units, must be loaded and unloaded gradually to allow adequate time for regulating devices to respond and avoid excessive voltage fluctuation.

The generation facility must not further deteriorate existing unbalanced conditions.

The generation facility shall not cause objectionable voltage and current unbalance conditions.

The generation facility shall not cause voltage imbalance beyond 3% and current imbalance beyond 10% at the PCC.

Reference: CSA CAN3-C235, IEEE 1547 Clause 4.1.1, DSC Appendix F.2 Section 3, CAN CSA C22.2 No. 257-06 Section 5.2.3

5) Synchronization Reference

The generation facility shall parallel with the distribution system without causing **a voltage fluctuation of +/- 4**% of the prevailing voltage at the PCC

Interconnection shall take place only when the differences in **frequency, voltage and phase angle** are within the limits shown below.

Total DG System Capacity	Frequency Difference	Voltage Difference	Phase Angle Difference
0-500kVA	0.3Hz	10%	20°
>500-1500kVA	0.2Hz	5%	15°
>1500kVA	0.1Hz	3%	10°

Reference: CAN CSA C22.2 No. 257-06 Section 5.3.21, IEEE 1547 Clauses 4.1.3, 5.1.2, DSC Appendix F.2 Section 3.2, OESC rule 84-006

6) Feeder Relay Directioning

To prevent sympathetic tripping of the DG feeder due to faults on adjacent feeders, breaker protection may need a directional feature for reverse fault current conditions.

Transmission Station relay settings may need to be changed so that protection systems are coordinated.

Reference: DSC Appendix F.2 Section 8, SYNERGY NORTH requirement

7) Monitoring Reference

A generation facility with total capacity rated **greater than 250 kVA** at the PCC, shall have active monitoring for items a) to d) below. A generation facility **greater than 50 kVA** shall have provisions for monitoring of items below to allow future telemetry.

a) Connection status

b) Real power output

c) Reactive power output

d) Voltage at PCC or aggregate connection

Monitoring typically includes status of load interrupting switches, circuit breakers and interface protection annunciation. Communication media options will be mutually agreed upon.

Reference: DSC Appendix F.2 Section 9, IEEE 1547 Clause 4.1.6, CAN CSA C22.2 No. 257-06 Clause 5.3.22

8) Power Factor Reference

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

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

c) 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 SYNERGY NORTH in the CIA.

d) 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

e) SYNERGY NORTH shall determine the required operating power factor of the DG Facility during the CIA study and shall specify this to the DG Owner.

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

g) 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.

h) DG Facilities greater than 10 MW (Class 4 DGs) shall be assessed by the IESO to determine whether the proposed generation is IESO-impactive[1] 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 DGs at all load conditions on the feeder.

Reference: DSC Appendix F.2 Section 4, CAN CSA C22.2 No. 257-06 Clause 5.3.13

1 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

9) Maximum Power Transfer & Synchronous Stability Reference

To ensure distribution system stability and prevent adverse effects on the steady state voltage profile of the feeder, the maximum power export of a generating facility shall be limited so as to not exceed 10° phase shift between line ends.

Reference: SYNERGY NORTH Requirement

10) Cease to Energize Reference

A. Distribution System Faults and Customer Facility Faults

Interface protection of the generation facility shall **cease to energize** SYNERGY NORTH's distribution system under the following conditions:

- **Internal Faults** within the DG facility.
- **External Faults** on the SYNERGY NORTH Distribution System.
- Equipment and Conductors energized from both directions shall have suitable protection from each supply source.

Reference: DSC Appendix F.2 Section 6.4,IEEE 1547 Clause 4.2.1, OESC 84-014, CAN CSA C22.2 No. 257-06 Clause 5.3.8

B. Feeder Breaker Reclosing Coordination

The generation facility shall cease to energize SYNERGY NORTH's feeder before automatic reclosing of the breaker takes place.

SYNERGY NORTH's 25 kV feeders incorporate an auto reclose operation typically half a second in duration.

Reference: IEEE 1547 Clause 4.2.2, DSC Appendix F.2 Section 6, CAN CSA C22.2 No. 257-06 Clause 5.2.9

C. Over-Voltage and Under-Voltage Protection

The typical range of protection settings shall comply with the following table:

Response to abnormal voltages

Voltage range (% of the base voltage [a])	Clearing time [b] (s)
V<50	0.16
50≤V<88	2.00
110<V<120	1.00
V≥120	0.16

[a] Base voltages are the nominal system voltages stated in ANSI C84.1 Table 1.

[b] DR ≤30 kW, maximum clearing times; DR >30 kW, default clearing times.

Reference: IEEE 1547 Clause 4.2.3, DSC Appendix F.2 Section 6.5, CAN CSA C22.2 No. 257-06 Clause 5.3.9, SYNERGY NORTH Requirement

D. Over-Frequency and Under-Frequency Protection

The generation facility shall cease to energize SYNERGY NORTH's distribution system at the frequency set points and clearing times outlined in the table below.

Response to Abnormal Frequency

DR size	Frequency range (Hz)	Clearing time [a] (s)
≤30 kW	>60.5	0.16
	<59.3	0.16
>30 kW	>60.5	0.16.
	<{59.8 to 57.0} (adjustable set point)	Adjustable 0.16 to 300
	<57.0	0.16

Unless otherwise specified by SYNERGY NORTH, the adjustable set point for generators larger than 30kW shall be set to 59.0 Hz and 300 seconds.

Reference: IEEE 1547 Clause 4.2.4, DSC Appendix F.2 Section 6.5, CAN CSA C22.2 No. 257-06 Clause 5.3.10, NPCC Regional Reliability Reference Directory 12, SYNERGY NORTH Requirement

E. Interface Protection System

The interface protection study shall include coordination of key interface protection elements, along with the proposed relays and settings to be used at the PCC. The protection study submission shall include required AC & DC schematics and wiring diagram.

Reference: DSC Appendix F.2 Section 6, SYNERGY NORTH Requirement

F. Source Configuration Change

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 SYNERGY NORTH

Reference: Hydro One Technical Interconnection Requirements Section 2.4.1, SYNERGY NORTH Requirement

11) Connection to SYNERGY NORTH's System Reference

Connection to SYNERGY NORTH's System following a grid disturbance shall take place only when the voltage at the PCC is within 6% and frequency between 59.5 and 60.5 Hz.

The generation facility shall reconnect no less than five (5) minutes after the system has stabilized within the above voltage and frequency ranges.

For large and mid-sized generating facilities that incorporate transfer trip protection, a lockout relay (86) shall prevent resynchronization until enabled by SYNERGY NORTH. 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.

Where multiple units on the same feeder are involved, staggering the reconnection times may be required.

Reference: DSC Appendix F.2 Section 6, IEEE 1547 Clause 4.2.6, SYNERGY NORTH Requirement

12) Anti-Islanding Protection and Transfer Trip Requirements Reference

The generation facility shall disconnect from SYNERGY NORTH's System upon the loss of utility supply voltage in one or more phases.

Local islanding protection at the generation facility is required.

For large, mid-sized, and aggregated generation facilities with capacity greater than 1 MW or 50% of the minimum feeder load or where the reclosing interval is less than 1.0 second, the design shall include a Transfer Trip scheme to prevent islanding. In this case, Distributed Generator End Open (DGEO) logic is to be included to supervise the auto reclose operation of the feeder breaker and mid-feeder recloser(s).

Reference: DSC Appendix F.2 Section 6.1.2, IEEE 1547 Clause 4.4.1, OESC rule 84-008, CAN CSA C22.2 No. 257-06 Clause 5.3.11, SYNERGY NORTH Requirement

13) Grounding and Generation Facility Reference

The generation facility's grounding scheme shall not cause over voltages that exceed the rating of SYNERGY NORTH equipment.

The generation facility will not disrupt the co-ordination of ground fault protection of SYNERGY NORTH's distribution system

Generation and interconnection facilities must be grounded as per manufacturer's specifications and the OESC.

Wind generation facilities may be restricted from connecting to the distribution system neutral.

Reference: DSC Appendix F.2 Section 2, IEEE 1547 Clause 4.1.2, OESC rule 84-030, CAN CSA C22.2 No. 257-06 Clause 5.3.6, SYNERGY NORTH Requirement

14) Power Quality

The generation facility must not negatively impact the power quality of SYNERGY NORTH's distribution system.

A) Limitation of DC injection

The maximum DC injection value is limited to 0.5% of the full rated output current (RMS) at the generation facility PCC after a period of six cycles following the paralleling with SYNERGY NORTH's distribution system.

Reference: DSC Appendix F.2 Section 10.3, IEEE 1547 Clause 4.3.1

B) Limitation of Flicker

The generation facility must not create objectionable flicker for other customers on SYNERGY NORTH's distribution system.

Reference: DSC Appendix F.2 Section 10.1, IEEE 1547 Clause 4.3.2, CAN/CSA-C61000-3-7

C) Limitation of Harmonics

Voltage distortions in percent of nominal voltage must not exceed the limits specified in IEC 610000-3-6

Reference: IEC 61000-3-6, DSC Appendix F.2 Section 10.2, IEEE 1547 Clause 4.3.3, CAN/CSA-C61000-3-6

15) Warning Signs and Diagrams

The following warning sign shall be posted on the point of disconnection, generator feeder cell and switch room door to warn people of the presence of DG:

WARNING

TWO POWER SOURCE

PARALLEL SYSTEM

As well, a single line, permanent and legible diagram of the switching arrangement shall be placed at the Customer's control room and the switch room to indicate the position of the distributed generators and isolation points with their interlocking arrangements.

Operating designations will be assigned to the switching equipment of the generation system as required by SYNERGY NORTH. The Customer shall update the single line electrical diagram and operating diagram to include the assigned operating designations, and the switching equipment shall be identified by the operating designations as well.

Reference: ESA-SPEC-004, ESA-SPEC-005-00

16) Maintenance Requirements–Protections & Control Systems Equipment

1. The DG Owner shall re-verify its Interconnection Protections and Control sub-systems that impact SYNERGY NORTH's Distribution System on a periodic basis, according to the following schedule:

   a) whenever any protections and control sub-system equipment requires replacement, design modification or changes to settings [1];

   b) every eight (8) years for Intelligent Electronic Device (IED) - based protection sub-systems that employ comprehensive self-diagnostic features [2] to detect and provide alarm telemetry to Distributor for internal sub-system failures;

   c) every four (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 SYNERGY NORTH 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 SYNERGY NORTH's Distribution System to acceptable levels of performance, as required by the Distribution System Code and Conditions of Service.

2. The protections 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 (described in the Distribution Connection Agreement).

3. Within three (3) months of Connection, the Customer shall provide SYNERGY NORTH 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.

a) Instrument transformer checks (insulation, ratio/polarity, excitation and resistance results) – should not require re-verification providing secondary load readings are correct (Item l) below);

b) Breaker timing trip tests for those breakers used to disconnect the Customer Facility from the Distribution System as a result of protection operations – may not be required if adequate Sequence of Events Recorder (SER) or Digital Fault Recorder (DFR) records are available to show correct timing has been sustained;

c) Verification of the transformer and neutral reactor/resistor impedances that impact the Customer 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 National Research Council (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 Customer 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 to end checks. This will require participation and coordination with SYNERGY NORTH and Hydro One Networks Inc - shall require re-verification;

4. The Customer shall make modifications to correct any problems that are found during re-verification. ,.

5. Within thirty (30) working days of receiving the above documentation or as required by the Code, Distributor shall notify the Customer 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 SYNERGY NORTH’s Distribution System. Such request for changes shall be sent to the Customer promptly

6. For those tests that require Distributor’s participation or witnessing, the Customer shall provide Distributor with no less than fifteen (15) working days’ notice prior to the test date.
7. All tests shall be coordinated and approved ahead of time through the normal outage and work management system planning processes.
8. The Customer shall complete the re-verification in accordance with Item (5) above and submit complete documentation of the test results to Distributor within one month of the completed tests.

Maintenance requirements are equivalent to what the Distributor requires for re-verification of its own facilities that have similar potential impact to the Distribution System.

1. *Distributor must be advised of and approve all interconnection equipment replacement, design modification and setting changes*
2. *Distributor will assess the adequacy of the self-diagnostic features of protection sub-systems based on the same criteria used for assessing Distributor feeder protections*