Yukon Energy Corporation

Independent Power Producers Interconnection Technical Guide

Revision: 04b
Release Date: 2019 01 24

Disclaimer

This report was prepared under the supervision of Teshmont Consultants LP ("Teshmont"), whose responsibility is limited to the scope of work as shown herein. Teshmont disclaims responsibility for the work of others incorporated or referenced herein.

Revision History

Revision Number	Date Released	Prepared by	Reviewed by	Comments
00	May 14, 2018	Robyn Tarrant, PEng Dwayne Aming, PEng	David King, PEng Robert Baker, PEng	First Draft
01	May 30, 2018	Robyn Tarrant, PEng Dwayne Aming, PEng	David King, PEng	Second Draft
02	June 5, 2018	Robyn Tarrant, PEng Dwayne Aming, PEng	David King, PEng	Third Draft. Incorporated YEC Comments.
03	June 18, 2018	Robyn Tarrant, PEng Dwayne Aming, PEng	David King, PEng	Fourth Draft. Incorporated YEC Comments.
04	September 17, 2018	Robyn Tarrant, PEng Dwayne Aming, PEng	David King, PEng	Fifth Draft. Incorporated YEC Comments.

Contents

Appendices

Appendix A	Information Required from IPP (Proposal Stage)
Appendix B	Information Required from IPP (Design Stage)
Appendix C	Information Provided by the Utility
Appendix D	Applicable Codes and Standards
Appendix E	Sample Operating Agreement
Appendix F	Typical Interconnection Single Line Diagrams
Appendix G	Protective Settings Commissioning Document

Executive Summary

The purpose of the Interconnection Technical Guide is to provide guidelines for Independent Power Producers (IPP) who wish to interconnect a generation facility of greater than 50 kW and up to 10 MW to the Yukon Integrated System (YIS) via the Yukon Energy Corporation (YEC) or ATCO Electrical Yukon (AEY) distribution systems. The maximum allowable generation at the Point of Interconnection (POI) between the distribution system and IPP will depend on the results of a system impact study conducted by YEC. This guide details the technical and operational requirements of the facility and is not intended to be used as a design guide.

The purpose of this document is to:

- Provide technical specifications for the interconnection of IPP generation to the YIS (via YEC or AEY distribution systems).
- Clarify, where necessary, the technical requirements in CSA Standard C22.3 No. 9-08 (R2015) "Interconnection of Distributed Resources and Electricity Supply Systems" [1] and to provide an outline for how each section applies to interconnections with the YIS.

1. Introduction and Scope

1.1. Purpose

This guide establishes criteria and technical requirements for Independent Power Producers (IPP) who wish to interconnect generation, with a net capacity greater than 50 kW and up to 10 MW, to the Yukon Integrated System (YIS), at the distribution level (35 kV and below), or at the transmission level (above 35 kV). This guide has been developed considering CSA Standard C22.3 No. 9-08 (R2015) [1] and IEEE Standard 1547-2018 [2] and is subject to regular review and revision due to evolving standards.

The technical guide is intended to assist IPPs who apply to connect to the YIS through the Standing Offer Program, Call for Power, or through other unsolicited requests to connect.

1.2. Limitations

The criteria and technical requirements described within this section apply to the following generation interconnections:

- Interconnections to the Yukon Energy Corporation (YEC) and ATCO Electric Yukon (AEY) distribution systems at voltages of 34.5 kV and below, and
- Interconnections to the YEC transmission system at voltages over 34.5 kV by means of an existing or new substation. Transmission interconnections will require specific detailed review and approval by YEC and all interconnection costs will be borne by the IPP.

This Guide establishes the minimum requirements for the Point of Interconnection (POI). The IPP generation may be subject to additional requirements to ensure the project meets all applicable standards.

This Guide is not to be used:

- As an Operating Agreement and does not address the following:
    - Joint operating agreements
    - Costs
    - Tariffs
    - Other contractual issues
- As an Interconnection Process and Procedures Guide, and does not include the following:
    - Protection of the IPP's generation facilities
    - Transmission system impact and upgrades
    - System planning and design
    - Operation of the distribution system
    - Other system related issues
- As a design handbook for a generation facility.
- For any IPP generation not connected indirectly or directly to the YIS, i.e. an island grid.

2. Terms, Definitions, and Abbreviations

2.1. Definitions

Accredited Certification Organization – An organization that has been accredited by the Standards Council of Canada to operate a certification program for electrical equipment, such as the Canadian Standards Association (CSA).

Anti-islanding – A means of detecting and preventing a DR from energizing a part of the distribution system that becomes disconnected from the grid.

ATCO Electric Yukon – A private investor-owned utility, and member of the ATCO Group of Companies.

Automatic Circuit Recloser (ACR) – An overcurrent protection device used by utilities to detect faults on distribution system feeders, which has the ability to open and then reclose after a specified time delay allowing adequate time for temporary faults to clear.

Bi-directional Meter – A meter that measures real and reactive power and energy in both directions.

Cease to Energize – The cessation of energy outflow capability.

Clearing Time – The time from the start of the abnormal condition to when the distributed resource ceases to energize the distribution system.

Dispensated Metering Equipment – Any metering equipment that has received Measurement Canada approval under Section 9(2) or 9(3) of the Electricity & Gas Inspection Act.

Disconnecting Means – A device or group of devices that allows the conductors of a circuit to be disconnected from their source of supply.

Distributed Generation (DG) – Small, decentralized electric power generation facilities, typically interconnected to the distribution system.

Distribution System – The portion of the electrical system that operates at a nominal voltage of 34.5 kV line to line and below, and which distributes electric power between distribution substations and customers.

Effectively Grounded Distribution System – Distribution facilities where the neutral conductor is solidly grounded and the ratio of the zero sequence reactance to the positive sequence reactance is less than or equal to 3 and the ratio of the zero sequence resistance to the positive sequence reactance is less than 1.

Electromagnetic Interference (EMI) – Any electromagnetic disturbance that interrupts, obstructs, or otherwise degrades or limits the effective performance of a device, equipment or system.

Exporting – supplying power into the distribution system through the POI.

Facilities – A physical plant including, without limitation, generating plants, transmission and distribution lines, transformers, meters, equipment and machinery.

Flicker – The subjective impression of fluctuating luminance caused by voltage fluctuations.

Frequency – The number of cycles through which an alternating current passes in a second. The North American standard is 60 cycles per second, known as 60 hertz (Hz).

Generation – The process of converting solar, thermal, wind, hydro, or chemical energy into electric energy.

Independent Power Producer (IPP) – An agency or individual other than a public utility (as defined by the Public Utilities Act) who generates electricity to sell (to the utilities). An independent power producer does not own transmission facilities and is dependent on the utilities to purchase and distribute the power it produces.

Interconnection – The physical connection of DG to YEC's distribution system so that parallel operation can occur.

Island Grid – A community power system which is energized solely by one or more local power producers and is separated electrically from the YIS.

Islanding – A condition where a portion of the utility's distribution system is energized exclusively by one or more power producers through their DR interconnection.

Operating Interface Point – See Point of Interconnection.

Parallel Operation – the simultaneous energization at a POI by the generating facility and the utility distribution system.

Point of Interconnection (POI) – The location of the electrical connection between an IPP facility and the utility's distribution system. This will be the point where the ownership changes from the utility to the IPP.

Power Factor – The ratio of active power to apparent power. It is the cosine of the phase angle difference between the current and voltage of a given phase.

Protection Scheme – The protection functions, including associated sensors, relays, and power supplies, intended to protect a distribution system or interconnection equipment.

Public Utility – As defined by the Public Utilities Act and Regulations (i.e., YEC and/or AEY).

Ride-through – The ability to withstand voltage or frequency disturbances inside defined limits and to continue operating as specified.

Secondary Injection Testing – A method in which low level signals obtained from current and voltage signal generators are injected into a power system protective device to test device response.

Stabilized – The state of the distribution system after voltage and frequency has returned to normal range for a period of at least five minutes (or another period of time, as agreed with YEC) following a disturbance.

Stand Alone – The state where a distributed generation can operate by controlling the frequency and voltage of their facility while in islanded or isolated mode.

Telemetering – Transmission of measurable quantities using telecommunications systems.

Total Demand Distortion (TDD) – The ratio of the root mean square of the harmonic content, considering harmonic components up to the 50th order and specifically excluding interharmonics, expressed as a percent of the maximum demand current. Harmonic components of order greater than 50 may be included when necessary.

Total Harmonic Distortion (THD) –The ratio of the root mean square of the harmonic content, considering harmonic components up to the 50th order and specifically excluding interharmonics, expressed as a percent of the fundamental. Harmonic components of order greater than 50 may be included when necessary.

Transfer Trip – A remote signal directed from an upstream device to command a DG to cease to energize the distribution system upon detection of an islanding condition and to prevent re-energization.

Transmission System –The portion of the system that operates above a nominal voltage of 34.5 kV line to line and transmits electric power between YEC substations.

Trip Time – The time between the start of the abnormal condition and the interconnection device ceasing to energize the distribution system.

Type Test – A test performed on a sample of a particular model of a device to verify specific aspects of its design, construction and performance.

Utility – See Public Utility (i.e., YEC and/or AEY).

Visible-Break Disconnect – A switch or circuit breaker by means of which the generator and all protective devices and control apparatus can be simultaneously disconnected under full load entirely from the circuits supplied by the generator. All blades or moving contacts must be connected to the generator side, and the design of the disconnect switch must allow adequate visible inspection of all contacts in the open position.

Voltage Flicker – A condition of fluctuating voltage on a power system that can lead to noticeable fluctuations in the output of lighting systems.

Yukon Energy Corporation (YEC) – A publicly-owned electrical utility that is the main generator and transmitter of electrical energy in Yukon.

Yukon Integrated System – The integrated Whitehorse-Aishihik-Faro and Mayo-Dawson electrical grids which are owned by YEC.

2.2. Abbreviations

ACR	Automatic Circuit Recloser
AEY	ATCO Electric Yukon
AEUC	Alberta Electrical Utility Code
CEA	Canadian Electricity Association
CEC	The Canadian Standards Association's C22.1-98 Safety Standard for Electrical Installations Part 1, also known as the Canadian Electrical Code
CSA	Canadian Standards Association
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers, Inc.
IPP	Independent Power Producer
LTC	Load Tap Changer
NEMA	National Electrical Manufacturers Association
POI	Point Of Interconnection
RTU	Remote Terminal Unit
SCADA	Supervisory Control and Data Acquisition
SCC	System Control Center
SIS	System Impact Study
YEC	Yukon Energy Corporation
YIS	Yukon Integrated System
YUB	Yukon Utilities Board

3. Party Responsibilities

Refer to the IPP Policy as released in January 2019 for the individual responsibilities of the Government of Yukon, utilities (YEC and AEY), Yukon Utilities Board and the IPP during the generation interconnection process.

3.1. IPP Responsibilities

The IPP is responsible to:

- Provide technical information to the utility as specified in Appendix A and Appendix B;
- Assume ownership of the facility including the design, installation, operation, and maintenance of all equipment, station and distribution line facilities from the POI to the IPP facility, unless otherwise agreed to in writing;
- Pay the costs of system interconnection in accordance with the commercial terms established by the utilities;
- Obtain all regulatory approvals, including environmental assessment approvals, if necessary, for the construction and operation of its facilities. The IPP facilities shall be designed, constructed, operated and maintained in compliance with the applicable statutes, regulations, by-laws, codes and technical requirements specified by the utility (e.g. remote monitoring etc.);
- Submit all specifications of its facilities and detailed plans to the utility for review prior to receiving permission to connect to their distribution system;
- Ensure the technical requirements given in the standards and codes in Appendix D are met;
- Ensure metering requirements are met (see section 12); and
- Negotiate the timing and any testing requirements for the commissioning process with YEC

3.2. YEC Responsibilities

YEC is responsible for the operation of the Yukon Integrated System (YIS) and for certain local distribution systems interconnected with the YIS. This guide applies to all transmission and YEC distribution system interconnections.

YEC is responsible for all system studies performed on the YIS. The IPP and AEY, in the case of an AEY interconnection, shall provide all necessary information to YEC for the interconnection of the IPP facility. The system studies conducted by YEC will be paid for by the IPP.

After receiving the application for interconnection, YEC shall provide the IPP, at the IPP's cost, the information specified in Appendix C.

3.3. AEY Responsibilities

AEY is responsible for the operation of certain local distribution systems interconnected with the YIS. This guide applies to these AEY distribution system interconnections.

After receiving the application for interconnection, AEY shall, in consultation with YEC, provide the IPP, at the IPP's cost, the information specified in Appendix C.

4. General Requirements

4.1. Standards

When planning, designing, and operating an IPP Generation Facility, the IPP shall meet all applicable national, territorial and local construction and safety codes and standards.

The interconnection facility must comply, as a minimum, with the following:

- All CSA Standards, including the Canadian Electrical Code (CEC),
- Applicable YEC and AEY standards and the requirements set forth in this Guide,
- National, Territorial and local Governing law, acts, by-laws and codes, and
- Alberta Electrical Utility Code (AEUC) [4].

Applicable standards are located in Appendix D, however not all may be applicable for the IPP facility and additional standards may apply.

The interconnection of new generation can adversely affect the electric service to existing or future customers. The IPP must work with the utility to mitigate any adverse effects.

The facility must be constructed and maintained to provide a safe environment for employees as well as the public. If the generation facility adversely affects other customers, the utility may disconnect it until such time as the concern has been mitigated. The IPP is responsible for any costs incurred as a result.

The IPP is required to install, operate and maintain the facility and to ensure it is in sufficiently good order and repair at all times. Maintenance shall conform to good electrical practice, adequate for safe parallel operation when connected to the YIS. The utility and the IPP shall share commissioning reports, operating procedures and annual shutdown, maintenance, and inspection reports.

4.2. Operating Requirements

A joint operating agreement template will be developed in conjunction with the utility. The agreement requirements are not included within the scope of this Guide. A sample operating agreement is located in Appendix E.

5. Site Specific Conditions and Capacity Limitations

During the preliminary stage of project development any limitations regarding the proposed interconnection, and any additional system upgrades required, will be determined in consultations between the IPP, YEC and AEY, if interconnected via an AEY distribution system.

A system impact study will be necessary to identify any site-specific conditions and capacity limitations of the distribution and/or transmission system. To facilitate the study, the utility and the IPP will exchange information concerning load, feeder characteristics, protection philosophies, station layouts, capacities, ratings and other relevant information of the distribution and/or transmission system. The utility controls reliability design and reliability standards.

Under certain circumstances, YEC and AEY may limit the size or reconfigure the proposed connection arrangement of the IPP facility in order to maintain the integrity of their system.

6. YIS Transmission and Distribution System Characteristics

6.1. YEC Transmission System

6.1.1. General System Configuration

The YIS is an 'Islanded grid' which has no interconnection with the main North American electric grid. The Yukon must produce all of its own power, and cannot generate more electricity than is there is load, since there are no neighboring markets into which to sell surplus energy.

The YIS includes the 138 kV Whitehorse – Aishihik – Faro (WAF) grid, the 69 kV Mayo-Dawson-Keno (MD) grid, and the 138 kV Carmacks-Stewart Transmission Line (CSTL) which interconnects the WAF and MD grids. YEC provides power to major industrial customers connected to the 69 kV and 138 kV grids.

A map of the YIS is shown in Figure 6–1.

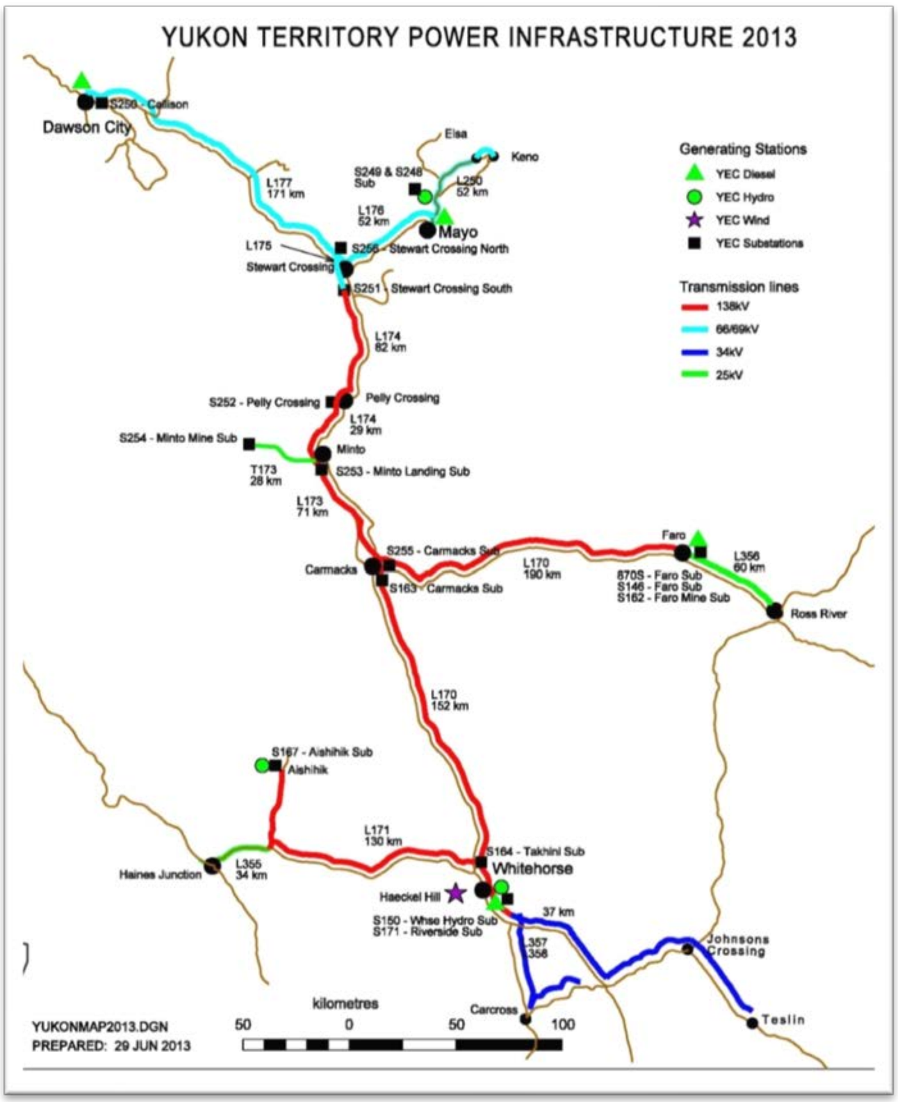


Figure 6–1: YIS Map

6.1.2. System Unbalance

Voltage unbalance on the transmission system is minimal during normal operation. The voltage unbalance under normal operating conditions will be less than three (3) percent. The IPP facilities may be subjected to voltage unbalance and negative sequence current during system disturbances. The generation connected to the transmission system must be able to withstand significantly unbalanced voltages with high negative phase sequence currents for short periods of time.

6.1.3. Frequency

The YEC transmission system operates at 60 Hertz (Hz) Alternating Current (AC) with equipment standard for this frequency. Frequency variations are typically in the range between 59.0 Hz to 61.0 Hz for small contingencies that cause modest disturbances, however variations between 58 Hz to 66 Hz or greater can occur for larger contingencies.

The frequency of the electric system is controlled by synchronous generator governor systems. Such governor systems respond automatically to changes in system frequency to prevent further deviation. These variations are system dependent and subject to change.

6.1.4. Steady State Voltage Levels

During normal steady state conditions, the 69 kV and 138 kV systems can vary between 90% and 105% of nominal voltage. However, under extreme conditions, the 69 kV and 138 kV systems can vary between 85% and 110% of nominal voltage with some 138 kV facilities designed to operate continuously up to 110% of nominal voltage.

6.1.5. System Fault Levels and System Impedances

The IPP generation facilities connecting directly to the transmission system shall be designed for operation at short circuit (fault) levels that take into account reasonable future development of the YIS transmission system. The short circuit levels to be used in the design depend on the point(s) of interconnection and future planned development and are available on request from YEC.

6.1.6. Fault Clearing and Automatic Reclosing

The YIS does not implement auto-reclosing at the transmission level.

6.1.7. System Grounding

The transmission system is effectively grounded.

6.2. YIS Distribution System Characteristics

6.2.1. General

Both YEC and AEY operate distribution systems in the Yukon which are interconnected with the YIS. The systems are predominantly three phase, wye connected, with nominal voltages of 4.16/2.4 kV, 6.9/4 kV, 12.5/7.2 kV, 13.8/8 kV, 25.00/14.4 kV and 34.5/20 kV.

AEY also operates a number of distribution systems which are not interconnected to the YIS, and are not covered by this Guide:

- Watson Lake
- Old Crow
- Beaver Creek
- Destruction Bay / Burwash Landing
- Swift River

For information on connecting to the AEY distribution systems which are isolated from the YIS, refer to AEY's document entitled, "ATCO Electric Yukon's Isolated Community Generation System Interconnection Guidelines".

6.2.2. Voltage Levels

The YEC and AEY distribution systems operate to meet CSA Standard CAN3 C235.83 – "Preferred Voltage Levels for AC Systems 0 to 50,000V" which defines the preferred operating voltage levels for normal and extreme operating conditions. The distribution system steady state voltage is typically maintained between + 5% to 7% and - 5% to 7%.

6.2.3. Power Quality (Harmonics and Voltage Flicker)

The YEC and AEY distribution systems operate to limit the maximum individual frequency voltage harmonics to 3% of the fundamental frequency and the voltage total harmonic distortion (THD) to 5% on the utility side of the POI.

6.2.4. Voltage Regulation

The operating voltages on the low voltage buses of YEC distribution substations are generally regulated by transformer automatic load tap changers (LTC), bus voltage regulators or feeder voltage regulators. YEC will provide set-points for the equipment upon request.

6.2.5. Voltage Unbalance

Distribution facilities are typically three-phase systems, incorporating single-phase distribution taps. The voltage unbalance on a distribution system under normal operating conditions may exceed 3%, due to the unbalanced loading and single-phase regulation. Voltage unbalance will be calculated using the following formula, as derived from CSA Standard C22.3 No. 9-08 (R2015) [1]:

Voltage Unbalance (%) = 100 x (negative sequence voltage of the fundamental frequency component) / (positive sequence voltage of the fundamental frequency component)

6.2.6. Fault Levels

Fault levels and maximum allowable fault currents vary significantly through the distribution system and must be considered in the design of the IPP interconnection.

6.2.7. System Grounding

The utility distribution facilities are typically three phase, four wire, multi-grounded systems that incorporate single phase distribution taps. The lines are normally operated as effectively (solidly) grounded with grounded-wye connected sources at the distribution substation secondary bus.

6.2.8. Phasing

The phase sequence on the utility system may vary, and must be confirmed between the IPP and the utility during the design phase of the installation.

6.2.9. Fault and Line Clearing and Automatic Reclosing

The YEC distribution systems do not currently include auto reclosing. The AEY distribution systems may have auto reclosing and this will be confirmed during the design phase of the application.

7. Power Quality Requirements for the System Interconnection

7.1. Harmonics

The following industry standards may provide guidance for appropriate performance.

- IEEE 1547-2018 – IEEE Standard for Interconnection and Interoperability of Distributed Energy Resource with Associated Electric Power Systems Interfaces, IEEE, 2018 [2]
- IEEE 519-2014 – IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems [5]
- IEC 61000-4-15 – Testing and Measurement Techniques – Flickermeter - Functional and Design Specifications [6]

The generation facility shall not inject harmonic currents such that will cause objectionable voltage distortion as per standard IEEE 519 Harmonic current injections cause intolerable voltage distortions on the distribution system and may damage equipment.

The Utility, at the IPP's expense, shall conduct a Power Quality Assessment of the distribution system in the immediate vicinity of the interconnection using a measurement technique compliant with IEC 61000-4-7.

When performing a Power Quality Benchmark, the measurements at the customer's POI shall be taken over a one week (168 hour) period during typical production load levels.

7.2. Flicker

The generation facility shall meet the requirements of Section 6.2.3 and shall not cause unacceptable levels of flicker on the distribution system. The utility, at the IPP's expense, shall measure the flicker level using a power quality measuring device that meets the requirements of the IEC Flickermeter Standard 61000-4-15.

When performing a Flicker assessment, the measurements at the customer POI shall be taken over a representative load cycle of one day or greater.

7.3. Speed Regulation and Frequency Control

The frequency of the YIS is controlled by the generators operated by YEC.

The YIS operates at 60 Hertz (Hz) Alternating Current (AC). The nominal frequency variations are typically 59.0 Hz to 61.0 Hz for small contingencies that cause modest disturbances, and the frequency may drop to 58 Hz or rise to 66 Hz or higher for larger contingencies.

The frequency of the YIS is automatically controlled by the governor systems of the generators operated by YEC, within the specified limits.

IPP generators rated at 1 MVA and greater are required to have a governor system, capable of operating in droop mode, to respond to system frequency changes. The droop setting of the governor will typically be in the range of 5%.

IPP generators rated less than 1 MVA may operate in base load mode rather than in frequency control mode.

The utility will define frequency requirements on a project by project basis and may require the control of these parameters directly via the YEC SCC.

Equipment connected to the YIS shall be capable of withstanding the dynamic frequency performance criteria listed in Table 1.

Table 1: Transmission Minimum Frequency Performance

Under Frequency Limit	Over Frequency Limit	Minimum Time
60.0-59.0 Hz	60.0-61.0 Hz	N/A (continuous operating range)
58.9-58.5 Hz	61.1-61.5 Hz	3 minutes
58.4-57.9 Hz	61.6-61.7 Hz	30 seconds
57.8-57.4 Hz		7.5 seconds
57.3-56.9 Hz		45 cycles
56.8-56.5 Hz		7.2 cycles
less than 56.4 Hz	greater than 61.7 Hz	Instantaneous trip

Under-frequency and over-frequency relaying that automatically disconnects generators from YIS must not operate for frequencies in the range of 59.0 to 61.0 Hz if no other abnormal system event is underway.

7.4. Voltage Regulation and Power Factor

The IPP is responsible for ensuring that the voltage levels at the POI are maintained within this guidelines prescribed by the utility. The IPP interconnection must maintain the voltage levels, under all feeder load conditions, at the same values as they were prior to the interconnection.

Synchronous generators connected to the distribution system must be equipped with adequate excitation controllers. The IPP shall operate generators with Automatic Voltage Regulators (AVR) adjustable from 95% to 105% of nominal bus voltage. The Generation should be run in Voltage control unless required to run in power factor (pf) mode by the Utility. Operation in MW or MVAR control is not acceptable. The AVR response should with no intentional delay when in Voltage Control mode.

Induction generators do not have voltage or reactive power control capability and consume reactive power (VAR). In this case, the generator must provide reactive compensation to correct the power factor to 0.9 lagging or better at the POI, unless other terms are specified by the utility.

Inverter type generating equipment can control the power factor over a wide range, typically ± 0.75. An inverter type generator connected to the distribution facility must be capable of adjusting the power factor in the range of ± 0.9. The IPP may operate outside that range only by prior agreement with the utility.

The utility will define voltage and reactive power requirements on a project by project basis and may require the control of these parameters directly via the YEC SCC. The IPP and utility will identify and agree on the exact transformer ratio to allow optimal voltage regulation on the system and the IPP will determine whether an on-load tap changer is needed.

In order to coordinate with its existing voltage control devices, the utility may require that the generator operate in a power factor control mode. This means operating within a constant power factor set point range. The voltage/power factor regulator must be capable of controlling the power factor of the generator. The utility shall determine the actual set point between these limits.

In power factor control mode, the voltage regulator must have a voltage override that causes it to reduce excitation if the voltage at the POI exceeds an upper limit to be specified by the utility. The normal upper limit is 105% of nominal; however, the voltage regulator shall have the provision to adjust this upper limit between 100% and 110% of nominal. The voltage regulator must also have provision for a time delay between sensing an excursion of the upper voltage and initiating control action. The power factor control equipment must have the capability to allow for the adjustment of this time delay from between 0 and 180 seconds. The utility will specify the required time delay for each project.

7.5. Voltage Unbalance

Unbalanced phase voltages and currents can affect protective relay coordination and cause high neutral currents and thermal overloading of transformers. Of particular concern is negative sequence voltage and the resulting effect, particularly on rotating generators and motors connected to the system.

To protect the utility and the IPP equipment, the 3-phase generation contribution at the POI should not cause a voltage unbalance greater than 1% or a current unbalance greater than 5%.

If the existing unbalance at the POI is shown to be already close to the maximum unbalance condition, the IPP contribution may cause the unbalance to exceed the specified amount. This will be considered on a case-by-case basis.

7.6. Voltage and Frequency Transients

The IPP is responsible for the cost of any necessary transient or dynamic stability studies, which must be performed in a manner approved by YEC.

7.7. Resonance and Self-Excitation of Induction Generators

The potential effects of resonance should be considered as part of the design of the generating facility. The effects include:

- Ferro-resonance in the transformer,
- Sub-synchronous resonance due to the presence of capacitor banks, and
- Harmonic resonance with other customers when capacitors are being added as part of the installation.

When induction generators are used, the potential for self-excitation should be assessed and addressed as part of the system impact study and mitigated accordingly.

The IPP shall be responsible for the engineering analysis as part of the design process to evaluate the existence of, and to eliminate the harmful effects of resonance and the assessment of the self-excitation effects of induction generators. The engineering analysis of resonance and the assessment of the self-excitation effects of induction generators must be submitted to YEC for approval or further evaluation.

7.8. DC Current Injection

The IPP facility system shall not inject a dc current at the POI.

7.9. Fault Levels

The utility will provide the IPP with the anticipated fault levels or the data necessary for the IPP to calculate the distribution system fault contributions at the POI.

The IPP facility must not increase the fault levels on the utility distribution or transmission system above their design levels for maximum faults.

8. Physical Interconnection

8.1. Safety

The safety of the public, operating personnel and the environment is of primary concern in the design, construction, operation and maintenance of the interconnection facilities.

8.2. Point of Interconnection (POI)

The POI is the point at which the utility (YEC or AEY) distribution facilities or conductors are connected to the IPP's facilities or conductors, and where any transfer of electric power between the IPP and the utility takes place. The POI must be identified in the design and on the Single Line Diagram (SLD).

Depending on ownership, YEC or AEY will coordinate the design, construction, maintenance and operation of the facility on the distribution system side of the POI. The IPP is responsible to coordinate the design, construction, maintenance and operation of the facility on the generation side of the POI.

All voltage and frequency parameters specified in this section must be met at the POI unless otherwise stated.

The IPP is responsible for any incremental costs to the electric systems caused by the interconnection. The responsible utility will carry out the engineering, design and construction required for these installations and charges those costs back to the IPP. Ongoing O&M costs incurred on the distribution feeder side will also be recovered by the utility.

There may be cases where either the utility or the IPP may own equipment located on the other's side of the POI. For example, the utility may own and operate communications, supervisory, or metering equipment, which is located on the IPP side of the POI. The IPP must provide a site with the necessary space for utility to install current transformers, potential transformers, switching equipment, meters, and any other AC and DC auxiliaries, protection and controls, SCADA or communications equipment required to interconnect with the generating facility. The site is to be approved by the utility and a 120-volt AC power service is to be available for the use of portable tools.

8.3. Point of Disconnection

For transmission interconnections, the visible-break disconnect switch shall be located on the high voltage side of the interconnection transformer.

For distribution interconnections, the visible-break disconnect switch may be located on the high or low voltage side of the interconnection transformer.

The disconnect switch must be gang operated to simultaneously isolate all three phases.

If the IPP site interconnects multiple generators, one disconnect switch must be capable of isolating all of the generators simultaneously. There may be other means of meeting this requirement; however the approval of the utility must be obtained before using other means.

The IPP must follow the utility switching, clearance and tagging procedures. The utility is responsible to instruct the IPP in this regard.

8.3.1. High Side and Low Side Disconnect Switches

For transmission interconnections the disconnect switch on the high voltage side of the interconnection transformer shall be installed, owned and maintained by the IPP.

For distribution interconnections the disconnect switch, if on the high voltage side of the interconnection transformer shall be installed, owned and maintained by the utility, and if on the low voltage side of the interconnection transformer shall be installed, owned and maintained by the IPP.

8.3.2. Disconnect Switch Specification

The disconnect switch must be a manual, visible-break disconnect that provides safe isolation for the utility's personnel from the generators and all other possible customer sources of energy.

The disconnect switch must:

- Be adequately rated to break the connected generation/load;
- Be located within five meters (horizontal) of the POI, unless otherwise approved by the utility;
- Provide a direct, visible means to verify contact operation;
- Allow simultaneous disconnection of all ungrounded conductors of the circuit;
- Plainly indicate whether the switch is in the "open" or "closed" position;
- Be lockable in the "open" position;
- Be capable of being energized from both sides;
- Be readily accessible to the utility's operating personnel;
- Be externally operable without exposing the operator to contact with live parts;
- Be capable of being closed without risk to the operator while there is a fault on the system;
- Be labeled with utility's switch number;
- Meet all applicable CSA Part II standards and all applicable codes; and
- Undergo annual inspections and maintenance, with reports submitted to the utility for approval.

8.4. Interconnection Transformer

A generator step-up transformer boosts the voltage of the DG to match the voltage of the utility distribution feeder. The transformer winding configuration impacts how system faults are detected and what type of protection is required (see Section 9.10). The IPP must submit their transformer connection proposal to the utility for review and approval prior to placing an order for purchase.

8.5. Interconnection Grounding

The IPP facility must be grounded in accordance with the latest revisions of the CEC and AEUC. A ground grid of sufficient size to handle the maximum available ground fault current must be designed and installed in order to limit ground potential rise (GPR) step and touch potentials to safe levels as set forth in ANSI/IEEE Std. 80 IEEE Guide for Safety in AC Substation Grounding.

The ground grid will be designed for foreseeable future fault levels obtainable from the System Impact Study.

Grounding of the interconnection shall be designed to provide:

- Solid grounding of the distribution feeder neutral connection,
- Fault detection that isolates all sources of ground fault contribution,
- A circuit to block the transmission of harmonic currents and voltages, and
- Protection of the low voltage side from damage due to high side faults.

The preferred configuration, for an IPP owned interconnection transformer, is delta connection on the generator side of the transformer and a grounded-wye configuration on the utility's side of the transformer. If this configuration is not technically feasible, the configuration chosen must still address the above concerns. Grounding must conform to the AEUC [4].

Sample single line diagrams are shown in Appendix F.

8.6. Phasing and Phasing Sequence

Since phasing is not standardized across distribution facilities, the phase sequence must be coordinated between the IPP and utility's distribution system.

8.7. Interrupting Device Ratings

The design of the generation facility must consider the fault contributions from both the distribution system and the IPP generation facility, to ensure that all circuit fault interrupters are adequately sized. The utility will inform the IPP of the present and anticipated future fault contribution from the interconnected electric system.

9. Interconnection Protection

9.1. General

The purpose of the IPP facility protection is to reduce the risk of damage to IPP and utility equipment and maintain the reliability of supply.

The protection scheme shall be designed to detect the following conditions at the POI:

- Balanced and unbalanced system faults (i.e. line-ground, line-line and three phase faults)
- Frequency variations
- Voltage variations
- Reverse power flow
- Islanding conditions
- Out of synchronism

Depending upon location, the protection scheme may be required to detect additional conditions such as open phase, ferro-resonance, negative sequence voltage, or zero sequence currents.

The protection scheme must fully coordinate with any existing distribution system protective devices. The IPP must submit a complete protection design package, including all relay settings, tripping schemes and schematics, to the utility for review and approval prior to installation. Both existing and ultimate bus fault levels should be considered. A sample Protective Setting Commissioning Sheet with guideline limits is included in Appendix G.

The point of measurement for voltage and frequency shall be at the POI or as agreed upon with the utility.

The IPP must revise and re-submit the protection information for any proposed modification.

9.2. Device Ratings

Equipment shall be rated to carry and interrupt the fault levels that are, or will be, present at the IPP facility - this includes the ultimate fault currents specified by the utility. The IPP's equipment covers all station and distribution facilities, including but not limited to all protection equipment forming the entrance and distribution line protection: circuit breakers, current transformers, potential transformers, secondary cabling, dc system/battery charger, switchboard wiring and protective relays.

9.3. Minimum Protection Requirements

The following minimum protection requirements shall be provided for an interconnected IPP facility:

- Overcurrent
- Over-frequency
- Under-frequency
- Over-voltage
- Under-voltage

Additional protection requirements are dependent upon the transformer configuration and the distribution system characteristics.

9.4. Phase and Ground Fault Protection

The IPP must install utility grade protective devices to detect and promptly isolate the generation facility for faults occurring either in the DG facility itself or on the distribution system. Virtual devices (i.e., computer or programmable-logic controller systems) are acceptable provided they meet standard utility practice for system protection and they have been type tested and approved by an independent testing laboratory.

The protective devices in the IPP generation facility must fully coordinate with the protective relays on the distribution system unless otherwise agreed. The IPP must calculate the protective device settings and submit the relay characteristics and settings to YEC for review and approval.

The generation facility must be able to detect the following situations and isolate itself from the distribution system:

- A short circuit between any phase(s) and ground (if distribution system is a grounded system)
- A short circuit between phase(s)

9.5. Over-Frequency and Under-Frequency Protection

Each synchronous generator must be capable of continuous operation between 59.0 Hz and 61.0 Hz and of limited time operation for larger deviations from normal frequency, as shown in Table 1.

Over/under frequency relays are normally installed to protect the generators from extended off-nominal operation. It is expected that larger (> 1 MW) synchronous generators shall remain connected to the system during frequency excursions. To ensure that the generator is not tripped prematurely, YEC will specify the minimum required time delays and levels for setting the IPP over/under frequency protection relays.

9.6. Over-Voltage and Under-Voltage Protection

The IPP must operate its generation facility such that the voltage levels on the utility's system are not significantly altered by the connection of the generation facility. IPP facility paralleling shall not cause voltage fluctuations of more than ± 5% at the POI.

The IPP must install necessary relays to trip the circuit breaker when the phase-to-ground voltage, measured on any one of the three phases, deviates outside predetermined limits. Under-voltage relays should be adjustable and should have a settable time delay to prevent unnecessary tripping of the generator on external faults. Over-voltage relays should be adjustable and may be instantaneous.

The interconnection facility must cause the generator to cease to energize the utility's system within the trip times indicated in Table 2. "Trip time" refers to the period of time between the start of the abnormal condition and the moment the interconnection device ceases to energize YEC's system.

To ensure that the generator is not tripped prematurely, the utility will specify the minimum required time delays and levels for setting the IPP over/under frequency protection relays.

Table 2: Response to Abnormal Voltages

RMS Voltage (based on 120V nominal)	Trip Time
RMS Voltage: V=<50%	Trip time: Instantaneous

RMS Voltage (based on 120V nominal)	Trip Time
RMS Voltage: 50% < V < 90%	Trip time: 120 cycles
RMS Voltage: 90% < V < 105%	Normal Operation
RMS Voltage: 105% < V < 120%	Trip time: 30 cycles
RMS Voltage: V >= 120%	Trip time: Instantaneous

The IPP may reconnect when the system is stabilized (i.e. voltage and frequency have returned to normal range for a time as identified by the utility).

9.7. Additional Protection

The utility may require additional protection on a case by case basis. Possible protection may include:

- **Unbalance or negative sequence protection**: The IPP generator is tripped on excessive current unbalance. This is important if fuse protection is used on the primary of the generator step-up transformer or for any other open phase condition
- **Broken delta protection (59G)**: Using a grounded wye-broken delta potential transformer, this protection can facilitate detection of ground faults on ungrounded systems.
- **Rate of change of frequency**: Protection to detect a power island condition.
- **Reverse power protection**: Protection to detect a generator motoring condition.

9.8. Anti-Islanding Protection

Islanding is the condition where the generation facilities and a portion of the distribution system have become isolated from the rest of the system, and continue to operate in isolated mode. Unless agreed upon by the utility, generating facilities shall not be permitted to remain connected to an islanded system, i.e. islanding is not generally allowed. Generation facilities may continue to supply station service loads while disconnected from the interconnection system.

Anti-islanding protection is required to:

- Prevent power quality issues to customers connected to the island,
- Avoid out-of-phase reclosing between the utility and the DR facility, and
- Prevent safety hazards created as a result of back feeding isolated portions of the utility distribution system.

For rotating generators, the IPP must install a transfer tripping scheme using tele-protection signals from the system to separate the DG facility from the distribution system in the event of an islanding condition.

Transfer tripping requirements are also applicable to induction generators, unless the IPP can demonstrate that that there is no potential for self-excitation. For inverter-based generation a detection scheme designed in accordance with the requirements of IEEE 1547 [2] may be acceptable.

The IPP is responsible for damage to the YIS caused as a result of failure to safely separate from the system during an islanding event or subsequently during reconnection to the system following the event.

9.9. Transformer Winding Configuration

The winding configuration of any three phase transformer will have an influence on the location of the protection measurement points and the level of protection required for the IPP interconnection. See Appendix F for examples for typical synchronous generator protection single line diagrams for different transformer configurations.

9.10. Conditions for Connecting to an Energized Distribution System

The IPP system must not energize the utility distribution system when the distribution system is de-energized or following the operation of any interconnection protection functions. The utility will inform the IPP facility when it is safe to reconnect to the distribution system.

Where transfer trip protection is installed, the transfer trip protection must ensure that the generator disconnects before a substation feeder breaker or intermediate automatic circuit reclose (ACR) operation. General requirements are:

- Generator lockout within 0.6 seconds of breaker or ACR opening; and
- Fail-safe lockout within 6 seconds of communication loss.

These conditions will be finalized via the operating agreement between the utility and the IPP.

9.11. Synchronization

Any DG facility able to generate voltage while disconnected from the YIS requires synchronization facilities before connection is permitted.

The IPP facility shall maintain in synchronism with the system while operating in parallel. The generating facility has the responsibility of maintaining synchronization with the system. The utility cannot synchronize to the generating facility. Any proposed synchronizing scheme must be submitted to the utility, prior to the installation.

For synchronous generators, an approved automatic synchronizing device must be provided in all cases where the plant is to be operated unattended. Automatic synchronizing shall be supervised by a synchronizing check relay. Synchronizing controls should satisfy the conditions in Table 3 for synchronous generators.

Table 3: Synchronization Criteria for Synchronous Generators

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

Induction generators do not require synchronization since there is no generated voltage prior to connecting to the distribution system. The generator speed shall be brought to within 0.5% of its rated value. These units may be started as induction motors using power from the distribution system provided that these units do not cause unacceptable voltage flicker as specified in Section 7.2 on start - up or on connect/disconnect. The interconnection process of the induction generator shall not create a voltage drop pf greater than 5 percent.

Inverter-type or line-commutating voltage-following equipment does not require synchronization facilities. Operation of the interconnection (or disconnecting of the DR facility) shall not cause voltage drop greater that 5 percent and shall meet the flicker requirements

9.12. Protection from Electromagnetic Interference (EMI)

The influence of EMI must not result in a change in state or mis-operation of the interconnection facility.

9.13. Surge Withstand Performance

The interconnection facility must have the capability to withstand voltage and current surges in accordance with the environments described in IEEE/ANSI C62.41 or C37.90.1

9.14. Batteries and Auxiliaries

Batteries and auxiliaries shall have sufficient capacity to ensure the operation of all DC loads during loss of AC supply. Typically the batteries must be capable of supplying the substation DC load for 8 hours.

9.15. Mitigation of Protection Scheme Failure

Relays with self-diagnostic features, which provide information on the integrity of the protection scheme, should be used whenever possible.

The protection scheme must be designed by a qualified professional engineer, or a competent technical person working with the utility's engineers, to ensure that the self-diagnostic feature is integrated into the overall protection scheme for the safe and reliable operation of the system.

Depending on the scheme and its design, where relays with the self-diagnostic feature do not trip the appropriate breaker(s), sufficient redundant or backup protection must be provided for the system. The malfunctioning relay must also send a signal to notify operating personnel to investigate the malfunction.

9.16. Instrument Transformers used for Protection

Instrument transformers used for protection must comply with CAN/CSA-C60044-6 or IEEE C57.13 [8].

10. Remote Monitoring and Information Exchange

The IPP facility shall provide information in real-time to YEC SCC regarding:

a. Connection or circuit breaker status,
b. Real and reactive power output in kW and kVAR,
c. Load Tap Changer (LTC) position of the interconnecting transformer,
d. Communication and RTU failure alarm,
e. Intelligent Electronic Device (IED)/Relay failed status, and
f. Voltage at the POI.

The communication protocol and the equipment required will be specified by YEC.

The IPP facility shall log the operation of any protective device, including which protection elements operated, and the status of the DG facility including power output, voltage, and current waveforms.

YEC may have additional requirements on a case by case basis.

If it is determined that the IPP facility will have an impact on YEC's Transmission Network, the IPP will be required to provide a Remote Terminal Unit (RTU) or Data Link to a YEC RTU capable of exchanging Supervisory Control and Data Acquisition (SCADA) information with the YEC Control Centre. The protocol for data exchange via the RTU shall be compatible with that used for communications used by YEC. The communication protocol and the equipment required will be specified by YEC.

The IPP will be required to provide the following typical data needed by the (SCADA) system:

a. Individual generator(s) MW and MVAR
b. Individual generator(s) MWh and MVARh
c. Generator(s) breaker status
d. Individual generator on/off status, if no generator breaker exists
e. Total station MW and MVAR
f. Station service MW, MVAR, hourly MWh and MVARh
g. Generator transformer(s) high voltage side breaker(s) and isolator(s) status
h. Bus voltage at high voltage bus
i. PSS status, if applicable
j. AVR status, if applicable
k. AVR voltage setpoint, if requested
l. Total plant MW setpoint, if requested
m. Generator step-up transformer tap setting, if requested

11. Construction

The construction and installation of the IPP's generating facility must meet all applicable statutes, regulations, by-laws and codes. The IPP is responsible for obtaining all permits and complying with all safety and environmental regulations, codes and assessment approvals, if necessary, for the construction and operation of its facilities. Copies of all permits, compliance reports and inspection documents must be provided to the utility prior to energizing the POI.

All single line diagrams provided to the utility must be drawn in accordance with IEEE standards and conventions, and must be stamped by a professional engineer assuming responsibility for the design.

12. Metering

12.1. General

Two meters, primary meter and backup meter, will be required at the IPP facility:

- The utility shall install, own, operate and maintain one meter (primary) necessary for measuring the energy and demand supplied to the YIS, unless otherwise specifically provided in a contract with the IPP. This meter shall remain the sole property of YEC. The meter will comply with Measurement Canada requirements and will be owned and maintained by YEC.
- The IPP shall install, own, operate and maintain the other meter (backup) which does not necessarily have to comply with Measurement Canada requirements.

Generators exporting power onto the distribution system shall be equipped with bi-directional meters with four-quadrant measurement capability. An appropriate number of channels are required for four-quadrant meters to separately record active and reactive power in both the export and the import directions.

The high voltage side of the interconnection transformer is designated as the Measured Billing Point for all energy imported and exported from the IPP facility.

The metering equipment will be:

- Suitable for use in the environmental conditions reasonably expected to occur at the installation site; and
- Appropriate for measuring the power system characteristics reasonably expected to exist at the installation under all power system conditions and events.

The IPP shall provide Measurement Canada Approved instrument transformers. Each meter shall be connected to its own individual core/winding. For the utility meter the IPP shall wire from the instrument transformers to the meter receptacle using CSA-approved tamper resistant conduit and accessories suitable for the utility meter or metering equipment.

For transmission interconnections the IPP will provide burden calculations for proposed instrument transformer secondary wiring, for approval by YEC. If necessary the wiring burden may have to be reduced, by increasing the CT secondary conductor size, to meet Revenue Meter requirements.

The IPP shall supply and install the meter base to meet the utility requirements. The utility will provide the specifications for the meter base during the design phase.

12.2. Meter Requirements

The primary meter supplied by the utility will:

- Be Measurement Canada Approved for revenue metering;
- Be dispensated, with accuracy class ratings for active and reactive energy management as per Table 4;
- Be verified and sealed in accordance with the Electricity and Gas Inspection Act;
- Be capable of maintaining the interval boundaries within 60 seconds of the hour and every quarter hour thereafter;

- Measure all quantities required to determine active energy and reactive energy transferred in the required directions at the Measured metering point;
- Provide a separate register to maintain the continuously cumulative readings of the active energy and reactive energy transferred in the required directions at the Measured metering Point;
- Retain readings and, if applicable, all clock functions for at least 14 days in the absence of line power;
- Be equipped with meter failure alarm and communication failure alarm;
- Communicate all metering and equipment status to the YEC system control centre via the IPP's communication equipment;
- Apply loss compensation (such as line losses) factors where applicable to the revenue meters; and
- The meter shall have an accuracy class of 0.2% or better.

The backup meter supplied by IPP will:

- The backup metering will be of the same accuracy class and capability as the primary metering and shall include all equipment to provide the necessary billing data.
- Be non- dispensated, with accuracy class ratings for active and reactive energy management as per Table 5;
- .

Table 4: Schedule of Accuracies for Dispensated Metering Equipment Approved Under Section 9(2) or Section 9(3) of the Electricity and Gas Inspection Act

Metering Point Capacity (MVA)	Points of Delivery	Points of Supply	Measurement Transformers Accuracy Class
10 and above	1.0%	1.0%	0.3%
10	1.0%	1.0%	0.3%

Table 5: Schedule of Accuracies for Non-Dispensated Metering Equipment Approved Under Section 9(2) or Section 9(3) of the Electricity and Gas Inspection Act

Metering Point Capacity (MVA)	Watthour Meter Accuracy Class	Varhour Meter Accuracy Class
10 and above	0.2%	0.5%
10	0.5%	1.0%

12.3. Measurement Transformers

The applicable winding(s) of the current and potential instrument transformers supplied and installed by the IPP must:

- Be approved by Measurement Canada for revenue metering.
- Be burdened to a degree that does not compromise the accuracy required by this guideline.
- Have a minimum of two cores per instrument transformer. One core connection for the utility meter and the other core connection for the IPP meter.
- Be used solely for metering and not to be used for any other purposes.
- Have an accuracy class rating that equals or exceeds the values specified in Table 4.

12.4. Remote Communications Equipment

The remote communications equipment may or may not be an integral part of the meter or the recorder. However, it must incorporate protocol schemes that will prevent the corruption of data during interval data transmission. The protocol must be suitable for the communications equipment type and nature of the communications media and path.

12.5. Password Protection

Two or more levels of password protection will be required for each meter data collection agency. One level is for full access to set time functions and a second level is for read only access to interval data and event logs.

12.6. Safety Requirements

The facility installation must conform to:

- Measurement Canada Standard Drawings;

- AEUC [4];
- CSA Standard C22.2 General requirements - Canadian electrical code, part II [7] ; and
- ANSI/IEEE C57.13-2016 IEEE Guide for Grounding of Instrument Transformers [8].

13. Interconnection Tests

13.1. General Testing Requirements

The IPP must notify YEC (and AEY if the interconnection is via the AEY distribution system) in writing at least three weeks prior to the initial energization and start-up testing of the IPP generation facility. YEC may witness any testing of the equipment and protection schemes associated with the interconnection. Tests must align with the requirements specified in IEEE 1547 and CSA 22.3 No 9-08.

13.2. Type Testing

Type testing is considered an acceptable method of verification where suitable and applicable equipment standards exist, and must be performed once for each specific protection scheme. All interconnection equipment must include a type testing procedure as part of the documentation in order to determine the protection settings meet the requirements set forth within this technical guide. A type test may be performed on one device of a combination of devices. In a case of a combination of devices which comprise a system, the testing will demonstrate that the devices are able to operate as a system.

The type tests shall be performed on a representative unit or system, either in a factory, testing laboratory, or in the field. Results from a resource within a similar product family or design, including hardware or software, shall be acceptable as a representative within the same product family where ratings are within 50% to 200% of the tested resource.

The following type tests must be performed in accordance with IEEE 1547.1 [9]:

- Temperature stability
- Response to abnormal frequency
- Response to abnormal voltage
- Synchronization
- Interconnection integrity
- Unintentional islanding
- Open phase
- Reconnect following abnormal condition disconnect
- DC injection (for inverters without interconnection transformers)
- Harmonics

13.2.1. Temperature Stability

The temperature stability test verifies the interconnection equipment maintains measurement accuracy of parameters over its specified voltage range.

13.2.2. Response to Abnormal Frequency

This test verifies the interconnected generation facility ceases to energize the connected system as specified to IEEE 1547.1 with regards to abnormal frequency.

13.2.3. Response to Abnormal Voltage

This test verifies the interconnected generation facility ceases to energize the connected system as specified to IEEE 1547.1 with regards to abnormal voltage.

13.2.4. Synchronization

This test verifies the interconnected IPP facility will accurately and reliably synchronize with the utility as per IEEE 1547.1.

13.2.5. Interconnection Integrity

The interconnection integrity test verifies the IPP facility meets the surge withstand requirements as specified in Section 9.14 when tested in accordance with IEEE 1547.1.

13.2.6. Unintentional Islanding

Where YEC requires an anti-islanding protection function (other than transfer trip) or minimum import power levels, this test verifies that an IPP facility will cease to energize in accordance with IEEE 1547.1.

13.2.7. Open Phase

The open phase test verifies that the IPP facility will cease to energize the utility interconnection upon the loss of an individual phase on the distribution network when tested in accordance with IEEE 1547.1.

13.2.8. Reconnect following Abnormal Condition Disconnect

This test verifies the functionality of the IPP facility interconnection component or system reconnect timer, which shall delay the reconnection to the utility following a trip event prior to the distribution system stabilization, as specified in Section 9.11.

13.2.9. DC Injection (for Inverters without interconnection transformers)

This test verifies that an inverter-based IPP facility will comply with the DC current inject limit specified in Section 7.9 when tested in accordance with IEEE 1547.1.

13.2.10. Harmonics

The individual current harmonics and the total demand distortion (TDD) of the IPP facility shall be measured and recorded under normal operating conditions to ensure the values are within the limits specified in Section 7.1

13.3. Production Tests

Production tests shall be conducted on each IPP generating unit and interconnection equipment prior to delivery to verify they meet the applicable standards and verify the operability of every generating unit manufactured for customer use.

The tests assume the equipment has met the applicable interconnection and interoperability requirements of the applicable standards and may be conducted as a factory test or performed as part of an evaluation or commissioning test. Facilities with adjustable set points shall be tested at a single series of test points specified by the manufacturer. The summary report must provide a list of normal and abnormal performance category capability, final function settings, and final operating mode settings.

The following production tests are specified within IEEE 1547.1:

1. Response to abnormal frequency
2. Response to abnormal voltage
3. Synchronization

14. Commissioning Tests and Verifications

14.1. General

Commissioning tests are tests and verification on the IPP facility equipment to confirm the system as delivered, designed, and installed meets the interconnection and interoperability requirements of this guide and the applicable standards. These tests include visual inspections, and may include operability and functional performance tests as required.

Prior to the energization of the IPP facility, or changes to the facility, verification testing must be performed and coordinated with the utility. After the equipment is installed and ready for operation, the testing must be performed by a qualified individual in accordance the manufacturer's published test procedures, or IPP developed procedures that have been approved by the utility. Qualified individuals include: licensed, professional engineers; factory-trained and certified technicians and licensed electricians experienced in testing protective equipment. The utility reserves the right to witness the verification test or to require written certification that the test was performed.

Verification testing must also be performed annually or when major system upgrades or modifications are carried out.

14.2. Interconnection Verifications and Inspections

The following commissioning tests and inspections shall take place:

a. Final IPP facility protection settings shall be verified, recorded, and provided to the utility. A sample protective settings commissioning report is located in Appendix G.

b. Visual inspection shall ensure the grounding coordination requirements in Section 8.5 have been met.

c. Visual inspection shall ensure the presence of a disconnecting means in accordance with Section 8.3 has been met.

d. The polarities, burdens, and ratios of field wired instrument transformers shall be verified as correct and in accordance with the design documentation.

e. Field installed power and control wiring shall be verified to be in compliance with drawings and manufacturer requirements.

f. For three-phase systems, the phase rotation of the distribution system and the IPP facility as installed shall be verified as compatible.

g. All monitoring and information exchange provisions shall be verified as functional in accordance with Section 10.

h. Calibration checks of each protective relay or the equivalent protection device shall be performed using injection of appropriate ac quantities, secondary injection, or set-point adjustment verification.

i. Functionality of the protective relays or the equivalent protection device, circuit breakers, and telecommunications equipment shall be tested to verify the system operates as intended.

j. Load tests of protective relays or the equivalent shall be conducted immediately after energization, where applicable.

k. The ohmic value and connection of the transformer neutral impedance grounding device shall be verified as correct.
l. Upon loss of DC power supply to the protective relays or the equivalent protection device, it shall be verified the protection scheme activates the interconnection circuit breaker.
m. Upon loss of a communication signal, it shall be verified the fail-safe transfer trip occurs when required by the utility in accordance with Section 9.8.
n. Inverter operation must be verified annually by operating the load break disconnect switch and verifying the generation facility shuts down and does not restart for five minutes after the disconnect switch has closed.
o. Any system depending on a battery for trip power must be checked for proper voltage and logged monthly. Once every four years, the battery must be replaced or a discharge test performed.
p. The IPP shall submit to the utility the station LAN design architecture for review during the conceptual design phase of the project.
q. The IPP is responsible for all hardware design, RTU drawings, installation, testing and commissioning.
r. The IPP shall prepare a preliminary but tested version of the RTU Configuration and a preliminary version of the Point Assignment, and send them to the YEC SCC, together with all RTU drawings, P&C drawings and DNP point lists of all LAN devices, at least ten weeks before the in service date.
s. The IPP and YEC SCC shall jointly test all control, status and analog points and confirm visibility at the SCC.

14.3. Disconnection Means Operability

Prior to the operation of the IPP facility, the disconnecting means provided in accordance with Section 8.3 operates as intended.

14.4. Energization Cessation

Tests shall be conducted in accordance with IEEE 1547.1 to verify the functionality of the protection that ensures the IPP facility does not energize the utility under the following conditions described within this standard:

1. Abnormal frequency
2. Abnormal voltage
3. Protection scheme failure

Additional protection functions shall also be verified in accordance with IEEE 1547.1 as needed. The following protective functions must be verified if used at the IPP facility:

1. If available, the anti-islanding function must be checked by operating a load break disconnect switch and verifying that the IPP facility ceases to energize the output terminals and does not restart once the load break disconnect switch has reclosed.
2. If reverse power or minimum power function is used to meet the interconnection requirements, the functionality must be tested using secondary injection techniques. Alternatively, this

function can be tested by the means of a local trip test or by adjusting the IPP output and local loads to verify that the applicable non-export criterion are met.

14.5. Re-Verification

Re-verification of the interconnection and interoperability requirements may be required when any of the following occurs:

- Functional software of firmware changes have been made to the IPP facility equipment;
- Any hardware component of the facility has been modified in the field, been replaced or repaired with parts that are not substitutive components compliant with the applicable standards;
- Protection settings have been changed after factory testing; or
- Protection functions have been adjusted after the initial commissioning / verification process.

15. Maintenance

The IPP has full responsibility for the maintenance of its equipment, up to the Point-of-Interconnection, consistent with the Interconnection Agreement and this Guide. The IPP shall maintain the facilities in accordance with Rule 2-300 of the Canadian Electrical Code to ensure safe parallel operation with the YEC or AEY system. Failure to do so may result in disconnection of the IPP generation facility.

The IPP must present to the utility the planned maintenance procedures and a maintenance schedule for the interconnection protection equipment, and keep records of such maintenance.

The utility reserves the right to periodically inspect the interconnection protection system to verify that it meets the requirements outlined in this document.

Maintenance procedures up to the POI will be performed in accordance with good utility practice and the utility's policies and procedures.

16. Marking and Tagging

The disconnect switch must be clearly marked as the "IPP Disconnect Switch" and tagged with an identification number approved by the utility. The IPP must follow the utility's switching, clearance and tagging procedures. The utility is responsible to instruct the IPP in this regard.

The IPP switchgear equipment must include the manufacturer name and the manufacturer's serial number.

17. Modification of Installation

The IPP shall obtain written approval from the utility before commencing any modification to the generation facility. If the change requires the installation or modification of equipment, the IPP shall provide documentation that the new equipment meets the requirements of Type and Production tests.

If the changes require modifications to the protection and controls information the IPP must obtain approval from the utility for the proposed modifications. Whenever changes are made to interconnection hardware or software that can affect the functions listed below, the potentially affected functions must be retested:

- Over-voltage and under-voltage
- Over-frequency and under-frequency
- Non-islanding function (if applicable)
- Reverse or minimum power function (if applicable)
- Inability to energize dead line
- Time delay restart after utility outage
- Fault detection, if used
- Synchronizing controls (if applicable)

To ensure that commissioning tests are performed correctly, the utility may require the ability to witness the tests and receive written certification of the results.

18. Technical Data Requirements

The following outlines the minimum data required at various stages for planning, design and commissioning the IPP's project. This data is required by YEC (and AEY if connected to AEY distribution system) to ensure suitable steps are taken to interconnect the IPP facility to the YEC system. Expanded data requirements for the proposal and design stages are located in Appendix A and Appendix B. The IPP Policy (in development as of June 2018) shall apply.

18.1. Proposal Stage

During the proposal stage the IPP Facility conceptual design must be submitted before any further detailed studies is approved by the utility. The list of information to be provided for this approval may be the result of preliminary discussions with the utility. Based on the information provided by the IPP, the utility will provide their proposition, their commitment and their own requirements concerning the connection of the IPP facility.

The following list of drawings and data required for the proposal stage of the project includes, but is not limited to:

- A Single Line Diagram (SLD)showing the following :
    - The proposed protection relays, circuit and fuses with fuse type and rating,
    - The connections of all substation equipment with voltage levels and equipment ratings
    - The location of the revenue metering equipment.
- Description of protection scheme
- Generating station site plan showing the layout and location (coordinates) of the generating plant and the location of lockable, "visible" disconnect device
- Based on the size of the project the utility may require more additional generator, exciter and speed governor data for a preliminary interconnection study.

18.2. Approval (Design) Stage

Once the project has been approved by the utility the IPP will proceed to submit the facility detailed design.

The following list of drawings and data required for approval stage of the project includes, but is not limited to:

- Single Line Diagram
- Description of protection scheme
- Control schematic
- Protection and control philosophy
- Major equipment nameplate schedules and statements
- Fuse and protective relay coordination study and settings
- Current transformer characteristic curve
- Measurement Canada approval numbers for instrument transformers

- Generating station site plan showing the layout and land location coordinates and legal description. The drawing should also show the proposed terminal pole or service manhole with the routing of aerial line or underground cables from utility to the generating station.
- SCADA Diagram
- Obtaining all permits and complying with all safety and environmental regulations, codes and assessment approvals, if necessary, for the construction and operation of its facilities.
- Proposed In-Service Date

18.3. Verified Stage

When the project is nearing completion, the IPP must submit the proposed testing, commissioning and start-up procedures to be performed before the facility is connected to the YIS.

The following list of drawings and data required for commissioning and verification stages of the project includes, but is not limited to:

- Commissioning report
- Copies of all permits, compliance reports and inspection documents
- Final Single Line Diagram
- Final protection scheme
- Final control schematic
- Protection and control philosophy
- Major equipment nameplate schedules, statements, test reports and data sheets
- Final fuse and protective relay coordination settings
- Current transformer characteristic curve
- Final generating station site plan showing the layout and land location coordinates and legal description

19. References

The technical guide was created using the following primary reference standards. Additional applicable standards are located within Appendix D.

[1] CSA Standard C22.3 No. 9-08 (R2015) – Interconnection of Distributed Resources and Electricity Supply Systems, CSA Group, 2015.

[2] IEEE 1547-2018 – IEEE Standard for Interconnection and Interoperability of Distributed Energy Resource with Associated Electric Power Systems Interfaces, IEEE, 2018.

[3] Energy Strategy For Yukon Independent Power Production Policy, Yukon Energy, Mines and Resources, 2018

[4] Alberta Electrical Utility Code, latest Edition

[5] IEEE Std 519-2014 - IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems

[6] IEC 61000-4-15: Testing and Measurement Techniques – Flickermeter - Functional and Design Specifications

[7] CSA Standard CAN/CSA-C22.2 NO. 0-10 (R2015) - General requirements - Canadian electrical code, part II

[8] IEEE Std C57.13-2016 (Revision of IEEE Std C57.13-2008) - IEEE Standard Requirements for Instrument Transformers

[9] IEEE 1547.1-2005 IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems

Appendix A

Information Required from IPP (Proposal Stage)

Appendix A
Information Required from IPP (Proposal Stage)

Independent Power Producer Contact Information

Company Name	
Company Address	
Commercial Contact	
Commercial Contact Name	
Commercial Contact Phone	
Commercial Contact Email	
Commercial Contact Address	
Engineering Contact	
Engineering Contact Name	
Engineering Contact Phone	
Engineering Contact Email	
Engineering Contact Address	
Operating Contact	
Operating Contact Name	
Operating Contact Phone	
Operating Contact Email	
Operating Contact Address	

Project Overview

Land Location	
Legal Location Description	
Proposed In-Service Date	
General Description	

Generator Data

Generation Type (Synchronous, Induction, Inverter)	
Single Phase or Three Phase	
Prime Mover Type	
Number of Generators	
Generator Nominal kW Rating	
Generator Nominal kVA Rating	
Generator Nominal kV Rating	
Power Factor, at Rated Output	
Annual Energy Production (MW-hr)	
Production Capacity Range(MW)	

Transformer Data

Transformer Rating (ONAN/ONAF, kVA)	
Transformer Voltage Rating (kV)	
Load Tap Changer steps	
Winding Connection	
Positive Sequence Impedance (%, ONAN base)	
Zero Sequence Impedance (%, ONAN base)	

Prime Mover Data

Prime Mover Type	

Drawings

General Site Map, Including IPP Generation Facility	
Preliminary Substation Layout Drawings	
Preliminary Protection & Metering Single Line	

Company Authorization

Authorizing Personnel	
Authorization Signature	
Authorization Date	

Appendix B

Information Required from IPP (Design Stage)

Appendix B
Information Required from IPP (Design Stage)

Independent Power Producer Contact Information

Company Name	
Company Address	
Commercial Contact	
Commercial Contact Name	
Commercial Contact Phone	
Commercial Contact Email	
Commercial Contact Address	
Engineering Contact	
Engineering Contact Name	
Engineering Contact Phone	
Engineering Contact Email	
Engineering Contact Address	
Operating Contact	
Operating Contact Name	
Operating Contact Phone	
Operating Contact Email	
Operating Contact Address	

Project Overview

Land Location	
Legal Location Description	
Proposed In-Service Date	
General Description	

Generator Data

Generation Type (Synchronous, Induction, Inverter)	
Single Phase or Three Phase	
Number of Generators	
Manufacturer	
Model	
Nominal kW Rating	
Nominal KVA Rating	
Nominal kV Rating	
Power Factor at Rated Output	
Maximum Authorized Real Power (MARP)	
Leading and Lagging Reactive Power at MARP	
Generator Grounding (Resistive, Reactive, None)	
Individual Generator Parameters - impedances in per unit, on nominal machine base	
Speed (RPM)	
Inertia Constant, H (generator)	
Direct Axis Synchronous Reactance , X_D	
Direct Axis Transient Reactance , X'_D	
Direct Axis Subtransient Reactance , X''_D	
Quadrature Axis Synchronous Reactance , X_Q	
Quadrature Axis Transient Reactance , X'_Q	
Quadrature Axis Subtransient Reactance , X''_Q	
Open Circuit Direct Axis Transient Time Constant, T'_{DO}	

Short Circuit Direct Axis Transient Time Constant, T'_D	
Open Circuit Direct Axis Subtransient Time Constant, T''_{DO}	
Short Circuit Direct Axis Subtransient Time Constant, T''_D	
Quadrature Axis Transient Time Constant, T'_{QO}	
Quadrature Axis Subtransient Time Constant, T''_{QO}	
Saturation Factor (1.0 per unit flux)	
Saturation Factor (1.2 per unit flux)	
Armature Resistance, R_A	
Stator Leakage Reactance, X_L	
Negative Sequence Resistance, R_2	
Negative Sequence Reactance, X_2	
Zero Sequence Resistance, R_0	
Zero Sequence Reactance, X_0	
Armature Short Circuit Time Constant, T_A	
Governor Droop (%)	
Short-time unbalanced current factor (K)	
Continuous negative sequence current level (%).	
Induction Generator Data (if applicable) - impedances in per unit, on nominal machine base	
Rating (kVA)	
Rated Power Factor	
Speed (RPM)	
Inertia Constant, H (generator)	
Stator Resistance, R_S	
Stator Reactance, X_S	
Rotor Resistance, R_R	
Rotor Reactance, X_R	
Armature Magnetizing Reactance, X_M	
Other Attachments	
Reactive capability curve (D-curve) comes with	
a. Under excitation limiter	
b. Over excitation limiter	

Exciter nameplate	
VEE curves	
Single line diagram	

Power Factor Regulator

Reactive Power Limit - Lagging (out)	
Reactive Power Limit - Leading (in)	
Accuracy Tolerance (%)	

Voltage Regulator

Voltage Regulator Range (V)	
Accuracy Tolerance (%)	

Transformer Data

Transformer kVA Ratings	
Transformer kV Ratings	
Cooling Type (ONAN, ONAF)	
Winding Connection	
Transformer Grounding (Resistive, Reactive, None)	
Grounding Impedance in Ohms (if applicable)	
Positive Sequence Impedance (%, ONAN base)	
Zero Sequence Impedance (%, ONAN base)	
Tap Details (if applicable)	
On-Load Tap Range	
On-Load Tap Size	
Off-Load Tap Range	
Off-Load Tap Size	
Other Attachments	
Factory Test Reports (minimum requirements)	
No Load Loss & Exciting Current Measurements	
Measurement of Load Loss & Impedance Voltage and Zero Sequence Impedance Measurements	

Prime Mover Data

Prime Mover Type	
Prime Mover Rating	
Inertia Constant (prime mover)	
Manufacturer	
Model	
Other Attachments	
Elevation versus Output Curve	
Ambient Temperature versus Output Curve	

Drawings Required

General Site Map, Including IPP Generation Facility	
Complete and Accurate Protection Diagrams	

Single Line Diagrams	
AC / DC Schematics	
Wiring Diagrams	
Major Equipment Nameplates (Transformer, Generator, etc.)	

Protection Requirements

Proposed Protection Schemes Provided	
Verified Interconnection Functionality Provided	
Inertia Constant (prime mover) Provided	
Maintenance Plans for Protection Devices Provided	
Maintenance Plans for Interrupting Devices Provided	

Compliance with Electrical Inspector

Permit or Equivalent Compliance Provided (Yes / No)	

Metering Requirements

Element (2 Element, 3 Element)	
Metering Service Provider	
Metering Data Manager	
Asset ID Number	

Company Authorization

Authorizing Personnel	
Authorization Signature	
Authorization Date	

D.1 Modelling Information

In some cases, a generator (or the aggregate generation on a line) is large enough that adjacent customers or the dynamic stability of utility's distribution system could be affected. The IPP is responsible for the cost of any required transient or dynamic stability studies, and the studies must be done in a manner suitable to, and approved by, the utility.

IPPs are responsible for ensuring the data they submit provides an adequate mathematical representation of the facility's electric behavior. If the data is not available prior to purchasing equipment, it must be submitted as soon as it becomes available.

The studies must accurately determine:

1. The impact of the IPP's facility on adjacent customers of the utility.
2. The dynamic stability, in aggregate, of the utility system.

Data may be supplied by the manufacturer or acquired directly by testing. It must include generator characteristics (i.e., speed, reactance, resistance, excitation system etc.) and governor characteristics (i.e., lead time/lag time constants, valve or gate opening data etc.).

The information requirements vary for induction generators and inverter generators, and for hydro or thermal systems.

Appendix C

Information Provided by the Utility

Appendix C

Information Provided by the Utility

After receiving the application for interconnection, the utility will provide the following information to the IPP, if required:

a. Single Line Diagram or maps of the system up to the POI.
b. Minimum and maximum 60 Hz source impedances (positive-sequence, negative- sequence and zero-sequence) at the POI.
c. Maximum and minimum normal and emergency system operating voltage ranges at the POI.
d. Harmonic impedance envelope at the POI if available.
e. Planning, operating and reliability criteria, standards and policies.
f. The results of a planning study (e.g. the System Impact Study) documenting the availability of the requested amount of system capacity and any other specific technical issues to be addressed.
g. Cost estimates and time schedule to build the upstream facilities.
h. Characteristics and settings of protection on the distribution system.
i. Costs to implement any required changes to the distribution system that are identified by the System Impact Study.

Some or all of this information will be required by the IPP to properly design the interconnection protection. The utility will identify when the costs of producing this information are to be assigned to the IPP.

Appendix D

Applicable Codes and Standards

Appendix D
Applicable Codes and Standards

D.1 Primary Standards

CSA Standard C22.3 No. 9-08 (R2015) Interconnection of Distributed Resources and Electricity Supply Systems

IEEE Standard 1547-2018 Standard for Interconnecting Distributed Resources with Electric Power Systems with Associated Electric Power Systems Interfaces

Power Quality Standards

ANSI C84.1-2016 American National Standards for Electric Power Systems and Equipment Ratings (60 Hertz). Establishes nominal voltage ratings and operating tolerances for 60 Hz electric power systems from 100 V through 1200kV.

IEEE Std. 493-2007 IEEE Recommended Practice for Design of Reliable Industrial and Commercial Power Systems (IEEE Gold Book).

IEEE Std. 519-2014 IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems.

IEEE Std. 1100-2005 IEEE Recommended Practice for Powering and Grounding Sensitive Electronic Equipment (IEEE Emerald Book).

IEEE Std. 1159-2009 IEEE Recommended Practice for Monitoring Electric Power Quality.

IEEE Std. 1250-2011 IEEE Guide for Identifying and Improving Voltage Quality in Power Systems.

In addition to the power quality standards, the following standards are applicable to the interconnection of generation facilities to YEC's system:

IEEE Std. 100 - 2000 IEEE Standard Dictionary of Electrical and Electronics Terms.

IEEE Std 315-1975 (Reaffirmed 1993) ANSI Y32.3-1975 (R1989) CSA Z99-1975 Graphic Symbols for Electrical and Electronics Diagrams (including Reference Designation Letters).

IEEE Std 929-2000 IEEE Recommended Practice for Utility Interface of Residential and Intermediate Photovoltaic (PV) Systems.

C37.1-2007 ANSI/IEEE Standard Definitions, Specifications and Analysis of Systems Used for Supervisory Control, Data Acquisition and Automatic Control.

C37.2-2008 IEEE Standard Electrical Power System Device Function Numbers, Acronyms, and Contact Designations.

C37.18-1979 ANSI/IEEE Standard Enclosed Field Discharge Circuit Breakers for Rotating Electric Machinery.

C37.20.1-2015 ANSI/IEEE Standard for Metal-Enclosed Low-Voltage (1000 Vac and below, 3200 Vdc and below) Power Circuit Breakers Switchgear.

C37.20.3-2001 ANSI/IEEE Standard for Metal-Enclosed Interrupter Switchgear.

C37.24-2017 ANSI/IEEE Standard for Evaluating the Effect of Solar Radiation on Outdoor Metal-Enclosed Switchgear.

C37.27-2015 ANSI/IEEE Standard Application Guide for Low-Voltage AC (635 V and below) Power Circuit Breakers with Separately Mounted Current-Limiting Fuses.

C37.29-1981 ANSI/IEEE Standard for Low-Voltage AC Power Circuit Protectors Used in Enclosures.

C37.50-1989 ANSI Standard Test Procedures for Low-Voltage AC Circuit Breakers Use In Enclosures.

C37.51-1989 ANSI Standard Conformance Test Procedure for Metal Enclosed Low- Voltage AC Power Circuit-Breaker Switchgear Assemblies.

C.52-1974 ANSI Standard Test Procedures for Low-Voltage AC Power Circuit Protectors Used in Enclosures.

C57.12-2015 IEEE Standard General Requirements for Liquid Immersed Distribution, Power and Regulating Transformers.

C57.12.13-1982 Conformance Requirements for Liquid Filled Transformers Used in Unit Installations including Unit Substations.

C57.13.1-2006 IEEE Guide for Field Testing of Relaying Current Transformers.

C57.13.2-2005 IEEE Standard Conformance Test Procedures for Instrument Transformers.

C37.58-2003 (R2010) ANSI Standard Conformance Test Procedures for Indoor AC Medium- Voltage Switches for Use in Metal-Enclosed Switchgear.

C37.90-2005 ANSI/IEEE Standard for Relays and Relay Systems Associated with Electric Power Apparatus.

C37.90.1-2002 ANSI/IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems.

C37.90.2-2004 ANSI/IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers.

C37.95-2014 IEEE Guide for Protective Relaying of Utility Consumer Interconnections.

C37.98-2013 ANSI/IEEE Standard for Seismic Testing of Relays.

IEC 1000-3-3 Limitation of Voltage Fluctuations and Flicker in Low-Voltage Supply Systems for Equipment with Rated Current Less than 16A.

IEC1000-3-5 Limitation of Voltage Fluctuations and Flicker in Low-Voltage Supply Systems for Equipment with Rated Current Greater than 16A.

UL1008 Transfer Switch Equipment.

UL 1741 Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources

IEEE P1547, DRAFT Standard for Distributed Resources Interconnected with Electric Power Systems.
Canadian Electrical Code, CSA no. C22-1, latest version.C22.2 No. 31- M89 (R2000) Switchgear Assemblies.

Can/CSA - C22.2 No. 1071 95Commercial and Industrial Power Supplies.

Can/CSA - C22.2 No. 1010.1-92 Safety Requirements For Electrical Equipment for Measurement, Control and Laboratory Use.

Can/CSA - C22.2 No. 144-M91 (R2015) Ground Fault Circuit Interrupters.

C22.2 No. 193-M1983 (R2014) High-Voltage Full-Load Interrupter Switches.

C22.2 No. 201-M1984 (R2014) Metal Enclosed High-Voltage Busways.

C22.2 No. 229-M1988 (R2014) Switching and Metering Centres.

CSA Standard CAN3 C235 83 Preferred Voltage Levels for AC Systems 0 to 50,000V.

Alberta Electrical and Communication Utility Code (formerly the Alberta Electrical and Communication Utility System Regulation 44/1976 or future amendments).

Measurement System Standard / Transmission Administrator Metering Standard GC301 Practices for Management and Transfer of Metered Data.

C37.04-1999 IEEE Standard Rating Structure for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis (ANSI/DoD).

C37.06-2000 American National Standard for Switchgear--AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis--Preferred Ratings and Related Required Capabilities.

C37.09-1999 IEEE Standard Test Procedure for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis (ANSI/DoD).

C37.010- IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis.

C37.011-2011 IEEE Application Guide for Transient Recovery Voltage for AC High- Voltage Circuit Breakers.

C37.012-2014 IEEE Application Guide for Capacitance Current Switching for AC High-Voltage Circuit Breakers Above 1000 V.

C37.013-1997 IEEE Standard for AC High-Voltage Generator Circuit Breaker Rated on a Symmetrical Current Basis.

C37.015-2017 IEEE Application Guide for Shunt Reactor Switching.

C37.081-1981 (R1988) Guide for Synthetic Fault Testing of AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis.

C37.081a-1997 Supplement to IEEE Guide for Synthetic Fault Testing of AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis.

C37.11-2014 IEEE Standard Requirements for Electrical Control for Electrical Control for AC High-Voltage (>1000 V) Circuit Breakers.

C37.13-2008 IEEE Standard for Low-Voltage AC Power Circuit Breakers Used in Enclosures.

C37.14-2015 IEEE Standard for DC (3200 V and below) Power Circuit Breakers Used in Enclosures.

C37.16-2009 IEEE Standard for Preferred Ratings, Related Requirements, and Application Recommendations for Low-Voltage AC (635 V and below) and DC (3200 V and below) Power Circuit Breakers.

C37.20.2-2015 IEEE Standard for Metal-Clad and Station-Type Cubicle Switchgear.

C37.23-2015 IEEE Standard for Metal-Enclosed Bus.

C37.30-1997 IEEE Standard Requirements for High-Voltage Switches.

C37.32-2002 American National Standard for Switchgear--High-Voltage Air Switches, Bus Supports, and Switch Accessories--Schedules of Preferred Ratings, Manufacturing Specifications, and Application Guide.

C37.34-1994 IEEE Standard Test Code for High-Voltage Air Switches.

C37.35-1995 IEEE Guide for the Application, Installation, Operation, and Maintenance of High-Voltage Air Disconnecting and Load Interrupter Switches.

C37.36b-1990 IEEE Guide to Current Interruption with Horn-Gap Air Switches.

C37.37-1996 IEEE Standard for Loading Guide for AC High-Voltage Air Switches (in Excess of 1000 V).

C37.38-1989 IEEE Standard for Gas-Insulated, Metal-Enclosed Disconnecting, Interrupter, and Grounding Switches.

C37.42-2016 IEEE Standard Specifications for High-Voltage (>1000 V) fuses and Accessories.

C37.44-1981 (R1992) American National Standard Specifications for Distribution Oil Cutouts and Fuse Links.

C37.54-1996 American National Standard for Switchgear--Indoor Alternating-Current High-Voltage Circuit Breakers Applied as Removable Elements in Metal-Enclosed Switchgear Assemblies--Conformance Test Procedures.

C37.55-2002 American National Standard for Switchgear--Metal-Clad Switchgear Assemblies--Conformance Test Procedures.

C37.57-2003 (R2010) American National for Switchgear--Metal-Enclosed Interrupter Switchgear Assemblies-Conformance Testing.

C37.66-2005 American National Standard for Requirements for Oil- Filled Capacitor Switches for AC Systems (1 kV to 38 kV).

C37.81-2017 IEEE Guide for Seismic Qualification of Class 1E Metal- Enclosed Power Switchgear Assemblies.

C37.85-1989 (R1998) American National Standard for Switchgear--Alternating- Current High-Voltage Power Vacuum Interrupters-Safety Requirements for X- Radiation Limits.

ANSI/IEEE C37.90.1-2102 Surge Withstand Capability (SWC) Tests for Relays and Relay Systems Associated with Electric Power Apparatus.

120-1989 (Reaff-1997) IEEE Master Test Guide for Electrical Measurements in Power Circuits.

1291-1993 IEEE Guide for Partial Discharge Measurement in Power Switchgear.

IEEE Std C62.23-2017 Application Guide for Surge Protection of Electric Generating Plants.

ANSI /IEEE C62.41-1991 Recommended Practices on Surge Voltages in Low- Voltage AC Power Circuits.

C57.13-2016 IEEE Standard Requirements for Instrument Transformers.

C57.13.3-2014 IEEE Guide for the Grounding of Instrument Transformer Secondary Circuits and Cases.

C57.98-2011 IEEE Guide for Transformer Impulse Tests.

C57.19.100-2012 IEEE Guide for Application of Power Apparatus Bushings.

C57.110-2008 IEEE Recommended Practice for Establishing Liquid-Filled and Dry-Type Power and Distribution Transformer Capability When Supplying Non-sinusoidal Load Currents.

C62.92.4-2014 IEEE Guide for the Application of Neutral Grounding in Electrical Utility Systems, Part IV – Distribution.

IEEE Std. 242-2001 Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems.

ANSI C12.20-2010 Electricity Meters 0.2 And 0.5 Accuracy Classes.

ANSI C62.1-1981 Surge Arresters for AC Power Circuits.

ANSI C62.11-2012 Metal-Oxide Surge Arresters for AC Power Circuits (>1 kV).

NEMA CC 1-2009 Electric Power Connectors for Substations.

NEMA LA 1-2009 Surge Arresters.

NEMA MG 1-2016 Motors and Generators

Appendix E

Sample Operating Agreement

Appendix E
Sample Operating Agreement

1. Purpose

This agreement outlines the steps to take to ensure a reliable and safe interconnection between the IPP and YEC and/or AEY through a variety of circumstances.

2. Definitions

Operating Authority: The organizational unit assigned responsibility for operating a portion of the electrical system. For each utility the YEC System Control Center (SCC) operator is the operating authority. For the IPP, the *<IPP Contact>* is the operating authority.

Operational Boundary/Interface Point or Point of Interconnection: The location on the electrical system at which responsibilities between Operating Authorities meet. The breaker *<Breaker ID>* is the interface point between the IPP and the utility.

3. Operational Information

Circuit Breaker Identification

List circuit breakers providing interconnection between IPP and the utility.

3.1 Interlocks

List identified circuit breaker interlocks with sequence information

3.2 Contact Information

SCC – Phone (867) *XXX-XXXX* or (867) *XXX-XXXX* (recorded lines)

Contact Name	Title	Phone Number
<Utility Contact>	Leadhand SCC	(867) *XXX-XXXX*
<Utility Contact>	Operation Coordinator	(867) *XXX-XXXX*
<Utility Contact>	Manager Operations	(867) *XXX-XXXX*
<Utility Contact>	Director of Operations	(867) *XXX-XXXX*
<IPP Contact>	<Contact Position>	(867) *XXX-XXXX*

3.3 Normal Operation

Under normal operating conditions the IPP facility will be connected to the utility grid. The breakers status under normal operating conditions is as follows.

Breaker	**Status**
<Breaker ID>	*Open/Closed*
<Breaker ID>	*Open/Closed*
<Breaker ID>	*Open/Closed*
<Breaker ID>	*Open/Closed*

4. Operating Procedures

4.1. Line L### (<Utility Line> to <IPP Facility>) Isolation

L### isolation requires the minimum notification defined in section 4.3, with the exception of emergency repairs. The utility will provide a Condition Guarantee on breaker <Breaker ID>. The Condition Guarantee is used in communications between external parties. It is a formal method of communication that switching has been completed. It ensures the status of the breaker/device will not change until the work is complete, the lock out tag out is surrendered and all workers are clear.

4.2. Voltage Support

Based on the power quality conditions defined in Schedule *<X>* of the Power Purchase Agreement (PPA) and system security requirements, SCC may request voltage support. Voltage support can be accomplished by placing IPP generation on line, or other means such as capacitor banks or transformer tap changing. If such support is part of the operating agreement then:

- When the IPP has generation online, the generators regulate the generator bus voltage between 100 and 105% of nominal and the utility shall have control of this set-point. Generators reactive output will be adjusted by the utility in real time, to regulate the system voltage, by pulsing the AVR voltage set-points. The IPP sets the acceptable range within which the utility can adjust voltage.
- The utility must have full SCADA visibility of the IPP substation and control of critical elements.

4.3. SCC Remote Monitoring and Control

- SCC will have visual indication of the IPP breakers, generator status, capacitor status and electrical measurement information for the IPP facility.
- The utility control will be limited to:
  - Approving requests from the IPP to connect and disconnect from the utility system
  - Approving requests from the IPP for changes in generation output
  - Requesting the IPP to disconnect from the utility system for operational and safety reasons
- All IPP requests must be communicated and approved by the utility
- The utility shall have control (open and close) of incoming line breaker *<Breaker ID>* at the IPP facility.

5. Operational Notification

5.1. Daily Operating Communications

Under normal operating conditions IPP will be supplying *<XXX>* kW to the YIS. Generation changes of more than *<XXX>* kW must be communicated and approved by the utility.

5.2. The transition from winter to summer and conversely summer to winter generation levels must be established with SCC with a minimum of 30 days' notice.

5.3. IPP Facility Planned Maintenance and Scheduling

The IPP shall operate under the utility approved maintenance procedures established.

To meet changing operating conditions and coordinate maintenance efforts, maintenance shutdowns by the IPP need to be communicated to SCC at least one week in advance for shutdowns of up to 12 hours and 30 days for shutdowns longer than 12 hours. Changes in the availability and capacity of the onsite generation need to be communicated to SCC. The utility and the IPP shall share annual shutdown/maintenance plans in February of each year.

5.4. Transmission and Distribution Maintenance and Scheduling

The utility performs annual line maintenance on its transmission and distribution lines, during which grid power to the IPP facility may be curtailed or suspended. The duration of this annual maintenance can be up to 14 days per calendar year.

The utility will provide a minimum of 30 days' notice of the start date and expected duration of work that will curtain or otherwise interrupt the supply of grid power to the IPP facility.

6. Loss of Supply Procedures

6.1. Loss of Supply - Short Term

In the event of a disturbance that results in the loss of grid power to the IPP facility, SCC will make one attempt to re-energize the line to the IPP facility. If successful the following steps apply to resume the IPP facility operation with grid power.

a) SCC will confirm the status of the breakers located at the IPP's POI.

b) SCC will request closed breaker <Breaker ID>.

c) Once complete and with confirmation from SCC the IPP facility may proceed with the restarting of their operation. The IPP will communicate to SCC on generation greater than <XXX> kW. The request to increase generation may be communicated verbally or via SCADA.

6.2. Loss of Supply - Long Term

In the event of a disturbance that results in the loss of grid power to the IPP facility and SCC is unsuccessful in re-energizing the line the following steps will apply.

a) SCC will confirm the status of the breakers.

b) At the direction of SCC the IPP personnel will start and stage their generation on line supplying power to the IPP facility.

c) Once the line to the IPP facility has been re-energized, SCC will request the IPP synchronize and close its POI breaker.

d) The IPP facility is now connected to YEC system. Once complete and with confirmation from SCC the IPP facility may proceed with resuming generation. The IPP will communicate to SCC on generation increases greater than <*XXX*> kW. The request to load up may be communicated verbally or via SCADA.

7. Revision and Approval

7.1. This Agreement comes into effect once it is signed by the IPP and the utility.

7.2. This Agreement will remain in effect unless cancelled upon the mutual agreement of both Parties.

7.3. The Parties shall provide 90 days' notice in writing of the intention to modify the Agreement.

7.4. The Agreement may be revised upon mutual agreement of both Parties. The agreement will be formally reviewed every two (2) years.

Approved by: ____
Yukon Energy Corporation

Approval Date: ________________________

Approved by: ____
ATCO Electrical Yukon

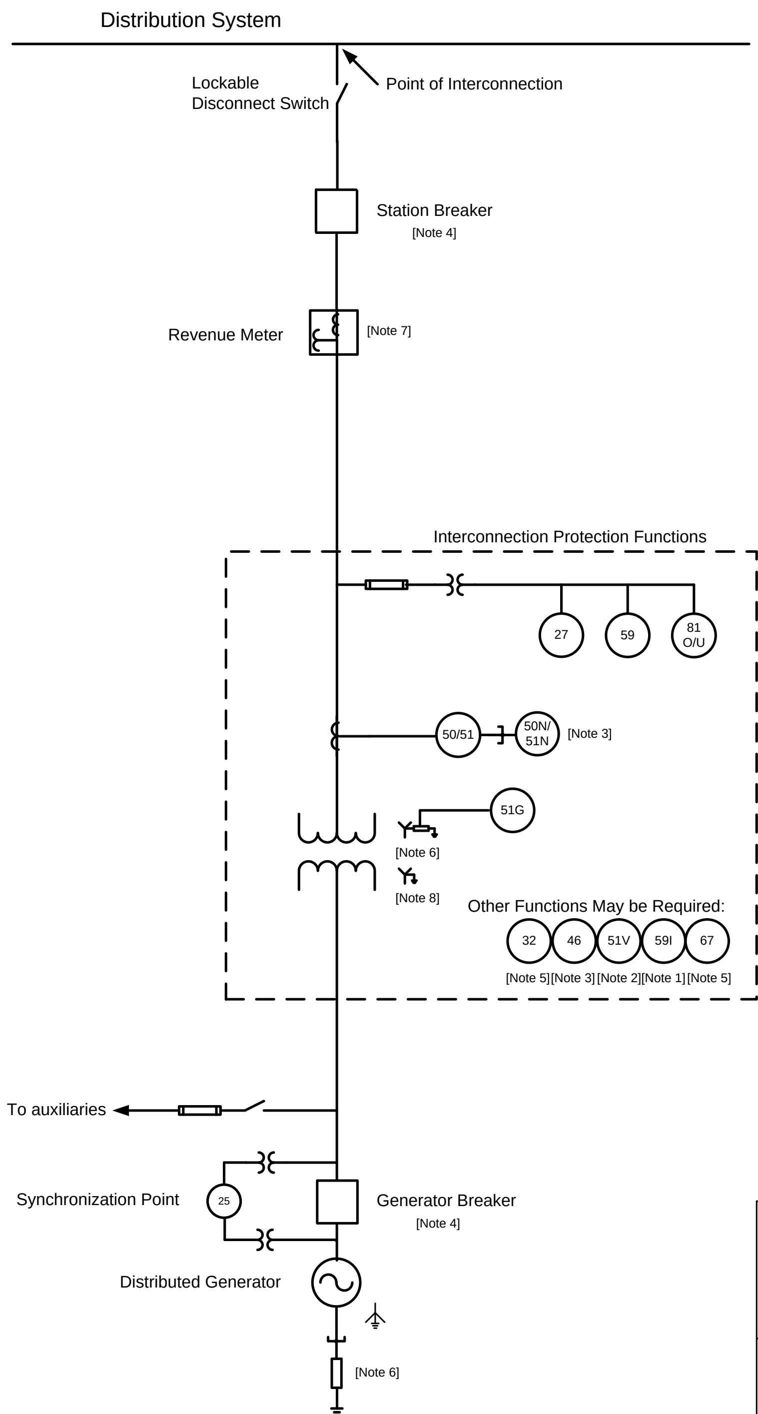
Approval Date: ________________________

Approved by: ____
IPP

Approval Date: ________________________

Appendix F

Typical Interconnection Single Line Diagrams



NOTES:

1. Required only if ferroresonance is possible.
2. Required if 27 operating time is too slow for feeder faults.
3. Device 46 can be used as an alternative to the 51N function.
4. Transfer trip is required only when generators are exporting to YEC.
5. Use to prevent islanding and non-export mode; must sense both real and reactive power.
6. Generator and transformer high voltage side must be effectively grounded, or solidly grounded. YEC approval will be required for grounding impedance.
7. Revenue metering, with the approval of YEC, may be located on the transformer secondary and corrected to Point of Common Coupling.
8. Transformer secondary voltage winding shall be ungrounded if generator winding is grounded.

PROTECTION LEGEND

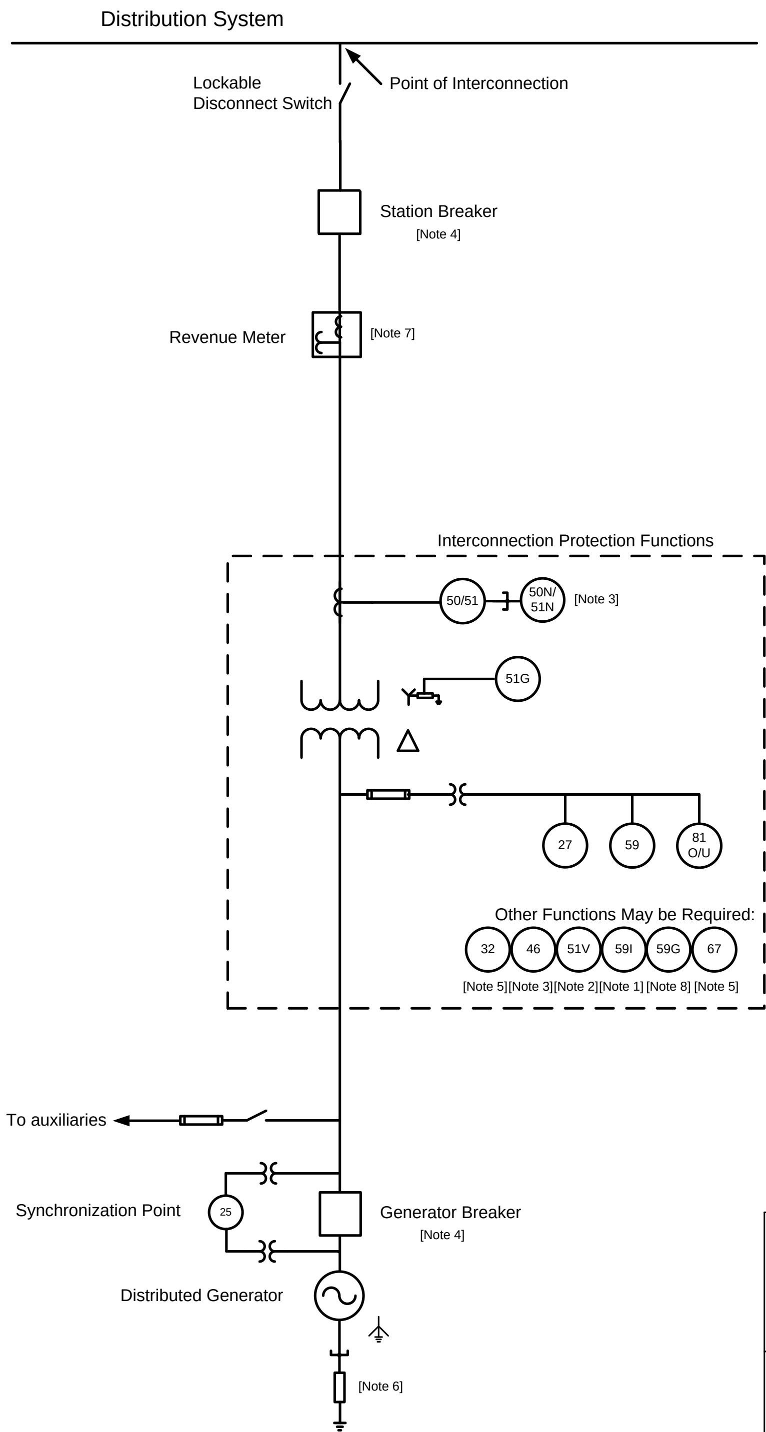
25 – Synchronism Check
27 – Under Voltage
32 – Reverse Power
46 – Negative Phase Sequence O/C
50/51 – Instantaneous/Timed Overcurrent
50N – Ground Overcurrent
51G – Neutral Overcurrent
51N – Neutral Overcurrent with Delay
51V – Torque Controlled Overcurrent
59 – Overvoltage
59G – Ground Overvoltage
59I – High Speed Overvoltage
67 – Directional Overcurrent
81/O – Over Frequency
81/U – Under Frequency

Typical Synchronous Generation Installation: Single Line Diagram for Wye-Wye Interconnection

Date:	By:	SLD No.
Aug-20-2018	MAI	Figure 1

Note: Typical requirements shown. Generator owner shall evaluate requirements for further protection

Figure F- 1: Single Line Diagram for Wye-Wye Interconnection



Note: Typical requirements shown. Generator owner shall evaluate requirements for further protection

NOTES:

1. Required only if ferroresonance is possible.
2. Required if 27 operating time is too slow for feeder faults.
3. Device 46 can be used as an alternative to the 51N function.
4. Transfer trip is required only when generators are exporting to YEC.
5. Use to prevent islanding and non-export mode; must sense both real and reactive power.
6. Generator must be effectively grounded, or solidly grounded. YEC approval will be required for grounding impedance.
7. Revenue metering, with the approval of YEC, may be located on the transformer secondary and corrected to Point of Common Coupling.
8. A Y-broken delta three phase is required to detect single phase line to ground faults.

PROTECTION LEGEND

25 – Synchronism Check
27 – Under Voltage
32 – Reverse Power
46 – Negative Phase Sequence O/C
50/51 – Instantaneous/Timed Overcurrent
50N – Ground Overcurrent
51G – Neutral Overcurrent
51N – Neutral Overcurrent with Delay
51V – Torque Controlled Overcurrent
59 – Overvoltage
59G – Ground Overvoltage
59I – High Speed Overvoltage
67 – Directional Overcurrent
81/O – Over Frequency
81/U – Under Frequency

yukon energy

Typical Synchronous Generation Installation: Single Line Diagram for Wye-Delta Interconnection

Date:	By:	SLD No.
Aug-20-2018	MAI	Figure 2

Figure F- 2: Single Line Diagram for Wye-Delta Interconnection

Appendix G

Protective Settings Commissioning Document

Appendix G
Protective Settings Commissioning Document

Over Voltage Protection Parameters

	PHASE VOLTAGE TO TRIP						DURATION TO TRIP					
	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED			GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED		
				A	B	C				A	B	C
Primary Trip	106% - 120% 1% Increments						30 Cycles					
Fast Trip	144% - 120% 1% Increments						100 ms					

Under Voltage Protection Parameters

	PHASE VOLTAGE TO TRIP						DURATION TO TRIP					
	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED			GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED		
				A	B	C				A	B	C
Primary Trip	50% - 90% 1% Increments						120 Cycles					
Fast Trip	Less than 50% 1% Increments						100 ms					

Non-Islanding Function Test

Loss of Utility Voltage	100 ms	
Generator Restart Delay	5 min Minimum	
Dead Bus Test	Fail to Start Successful (Yes/ No)	

Over Frequency Protection Parameters

	FREQUENCY TO TRIP						DURATION TO TRIP					
	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED			GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED		
				A	B	C				A	B	C
Primary Trip	60.5 Hz - 61.5 Hz 1% Increments						3 minutes					
Fast Trip	61.5 Hz - 61.7 Hz 1% Increments						30 seconds					

Under Frequency Protection Parameters

	FREQUENCY TO TRIP						DURATION TO TRIP					
	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED			GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED		
				A	B	C				A	B	C
Primary Trip	59.5 Hz - 58.5 Hz 1% Increments						3 minutes					
Second Trip	58.5 Hz - 57.9 Hz 1% Increments						30 seconds					
Third Trip	57.9 Hz - 57.4 Hz 1% Increments						7.5 seconds					
Fourth Trip	57.4 Hz - 56.9 Hz 1% Increments						45 cycles					
Fifth Trip	56.9 Hz - 56.5 Hz 1% Increments						7.2 cycles					
Fast Trip	Less than 56.4 Hz 1% Increments						100 ms					

Reverse AC Current Protection Function

	CURRENT TO TRIP						DURATION TO TRIP					
	DESIGN VALUE	ADJUSTABLE RANGE	AS SET	TESTED			DESIGN VALUE	ADJUSTABLE RANGE	AS SET	TESTED		
				A	B	C				A	B	C
Primary Trip												

Syncronization Limits for Synchronous Generators

	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET
Frequency Difference	+ 0.2 Hz		
Voltage Difference	5%		
Phase Difference	10° (degrees)		

Phase and Ground Fault Protection

	MAXIMUM CURRENT OR VOLTS TO TRIP						DURATION TO TRIP					
	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED			GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET	TESTED		
				A	B	C				A	B	C
Phase Current							200 ms					
Neutral Current							200 ms					

Transfer Trip Protection

	GUIDELINE LIMIT	ADJUSTABLE RANGE	AS SET
Generator Lockout	0.6 seconds		
Fail Safe Lockout	6 seconds		

Test Certification and Historical Data

Type Of Test	**Original Commissioning Test**		**Protection System Re-Test**	

Date of Test

Utility Representative Title

IPP Owner Representative

Signature

IPP Owner Representative Title

Date

Signature