Operational Experience of Microgrid in the BC Hydro System - A Case Study

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Abstract: *With* reduced cost of renewable technologies, increased customer demand for reliable and secure power, and societal climate change concerns, new green energy resources are gaining more popularity. These resources are typically small in size and distributed throughout the network. Rising penetration of new green resources is shifting the architecture of modern power grid where centralized and remotely located large generation facilities are being replaced with multiple small distributed resources that are located closer to customers. The distributed generation improves service reliability for customers when there is a planned outage or permanent fault in the electric supply chain from the integrated utility system. The customer along with local distributed generator can form a sustainable island which can operate as a Microgrid until the connection to the integrated system is restored. This concept is similar to earlier power plants that supplied power to customers in its neighborhood only.

This paper presents an example of a remote BC Hydro distribution substation which was originally built as traditional distribution substation and designed for unidirectional power flow from system to the station. In time, several run-of-the-river generating stations were connected to the distribution feeders at this station. Except during some winter months when rivers are frozen, total local generation often exceeds the station load and contributes to bi-directional power flows. The substation is connected to the integrated system from a single long radial transmission path. Recently, planned maintenance work on the terminal equipment of the radial supply line at this substation was required. Since the local generation was able to meet station demand, protection and control modifications were made to allow the station to operate as a standalone island or Microgrid to avoid the customer outages. Microgrid powered by run-of-the-river generation now limits usage of the backup diesel and helps to reduce costs as well as carbon footprint.

The paper discusses carefully planned switching sequences required to migrate from integrated to Microgrid operation and challenges of resynchronizing back to the system. The paper also discusses how the load and distributed generation balancing was achieved during a recent Microgrid operation. Operation in islanded mode will be described along with voltage and frequency regulating devices that are needed to adjust voltage and frequency limits with multiple generator units operating. Power Quality protection settings for each generating plant will be discussed. Protection challenges faced with reduced fault levels and provision of alternate settings group is listed and its remote control provided to Control Centers.

Key Words*: Microgrid, Distribution Generator Connection, Distributed Energy Resources (DER), Distributed Generator (DG), Islanded-Operation*

Operational Experience of Microgrid in the BC Hydro System: A Case Study

1. Introduction

This paper presents an example of a Microgrid which evolved from a traditional BC Hydro distribution substation. It is a remote station and connected to the integrated system from a single long radial transmission path with history of outages. Over the years, third-party owned small generators were connected at the distribution substation. Initially, the generators were designed to operate in parallel with the BC Hydro system. Their operation with the loads and station disconnected from the integrated was not allowed. Recently there was planned maintenance, involving work on the terminal equipment of the radial supply line. To avoid the customer outages, protection and control system changes were made. These changes now permit station to operate as Microgrid with local generation and loads during its planned disconnection from the integrated system. Previously, BC Hydro relied upon local diesel generation to supply some customers during transmission outages. The Microgrid operation, which is powered by run-of-the-river generation, now helps to reducing carbon foot print by curtailing diesel generation usage.

The paper provides switching methodology used for planned transition of station from grid-connected to standalone sustainable island and finally reconnection. The lessons learned will be discussed because first the attempts on transition and resynchronizing did not go as planned and led to customer interruptions. How the load and distributed generation balancing was achieved prior to and during the islanded operation. Operation in islanded mode is described along with voltage and frequency regulations, regulating devices that are needed to adjust voltage and frequency limits with multiple generator units operating. Power Quality protection settings for each generating plant will discussed. Protection challenges faced with reduced fault levels and provision to use SCADA enabled alternate settings group.

2. Standard Definitions

EPS: An Electric Power System (EPS) is a network of electrical components built for transmitting electrical energy from generating sources to end consumers.

DER: A Distributed Energy Resource (DER) is any resource on the distribution system that produces electricity and is not otherwise included in the formal NERC definition of the Bulk Electric System (BES) [1]. Therefore, DERs can be defined as small scale units of local generation connected to the grid at distribution level that can be utilized to meet power and reliability requirements of customers.

DG: Distributed Generation (DG) refer to small sources of electric power generation (typically ranging from less than a kW to tens of MW) outside of the Utility grid which are located close to the load.

Microgrid: A Microgrid is an area of the power system that has a large concentration of DG among various loads. What makes this system unique is that it can operate either in parallel with the Utility grid or in an autonomous way, disconnected from the Utility grid. This type of grid paradigm is particularly interesting in terms of the technical, reliability and economic implications. In many ways, a Microgrid is just a small-scale version of the traditional power grid. IEEE Std. 1547.4-2011 [2] defines DER island systems or Microgrids as electric power systems that:

- have DER and load,
- have the ability to disconnect from and parallel with the area EPS,
- include the local EPS and may include portions of the area EPS, and
- are intentionally planned.

In this paper DER, DG and local generation are used interchangeably. Likewise, Microgrid and Islanded operation are used interchangeably.

3. Benefits of Microgrid

With technological advancements, it is becoming more viable to have DERs closer to customers. These resources could be either wind farms or biogas plant or photovoltaic technology or traditional hydro machines. This section briefly outlines a few of the benefits of DER and allowing their operation in islanded mode with local loads or as a Microgrid.

Economic Benefits: With local generation available, upgrades to the integrated system, for example, transmission lines can be deferred. It reduces power loss. It can provide better voltage control and reduces on-line tap changing operations which helps reducing maintenance work on the utility assets. Local generation can provide jobs in the vicinity.

Voltage Quality Improvement: Local generation resources can be utilized to improve the local voltage profile. As in the example presented all local generators can operated in voltage regulating mode, so the plants provide and absorb reactive power as required to maintain setpoint voltage.

Alleviate Over Loading: During peak load hours, with proper utilization of DG, local area over loading can be avoided.

Environmental Concerns: By not having to construct new transmission lines or build new substations in the Integrated system, natural habitat will not be disturbed.

Reliability: Microgrids are a viable option for areas where there is an unreliability of power supply. A Microgrid can improve reliability for system outages and customers can have secure power supply.

4. Microgrid Protection Issues

Whether or not Microgrid operation is viable is challenging to evaluate and depends on many factors which include:

- Isolation and separation points in the system
- Mix between load and generation in the isolated system
- Microgrid generator protection system
- Microgrid generator control system: excitation and governor characteristics
- Visibility of DG units to a controlling entity (e.g. BC Hydro) over SCADA

Referring to Figure 1, a DG is connected to a typical utility distribution substation. DG and utility can separate at different points depending upon which breaker opens. Depending upon the ability of DG to support the load and form a sustainable island after separation, a feeder, bus, station and transmission level Microgrid can be formed. Protection challenges are different at each level.

Feeder Level Microgrid:
This configuration allows for supplying loads on the feeder when the planned outage is carried out with feeder circuit breaker open. Assuming that the feeder generation and loads can form a sustainable island, the following protection upgrades are required to the traditional distribution feeder protection originally designed for unidirectional power flow:

- Synchronizing with voltage supervision for auto reclose and remote circuit breaker close with feeder side voltage transformers or dead bus close
- Mitigation of feeder ground relay desensitization with DG generator operating in parallel with utility system (discussed in detail later in this section)
- Coordination for adjacent feeder faults
- Large variation in fault levels: from increased fault level when DG operating in parallel with the utility to drastic reduction when DG is operating in Microgrid mode
- Out of step protection

Station Bus Level Microgrid:
This configuration allows for supplying station loads when planned outage is carried out with the station bus breaker open. Assuming that the station generation and loads can form a sustainable island, the following protection upgrades are required in addition to all those discussed for the feeder level:

- Extend bus protection tripping to all feeders with DG to remove fault current infeed from local generation
- Directionalize bus protection

Transmission Level Microgrid:
This configuration allows for supplying transmission and station loads when the planned outage to be carried out at the remote station with line source breakers open. Assuming that the station generation and station plus line loads can form a sustainable island, the following protection upgrades are required in addition to all those discussed for the station bus and feeder levels:

- Add line protection to trip the local generator feeder circuit breaker
    - Phase faults – distance, overcurrent and timed overvoltage
    - Ground faults – zero sequence overvoltage
- Reclose supervision at line end substations
- Add zero sequence overvoltage due to ungrounded system operation

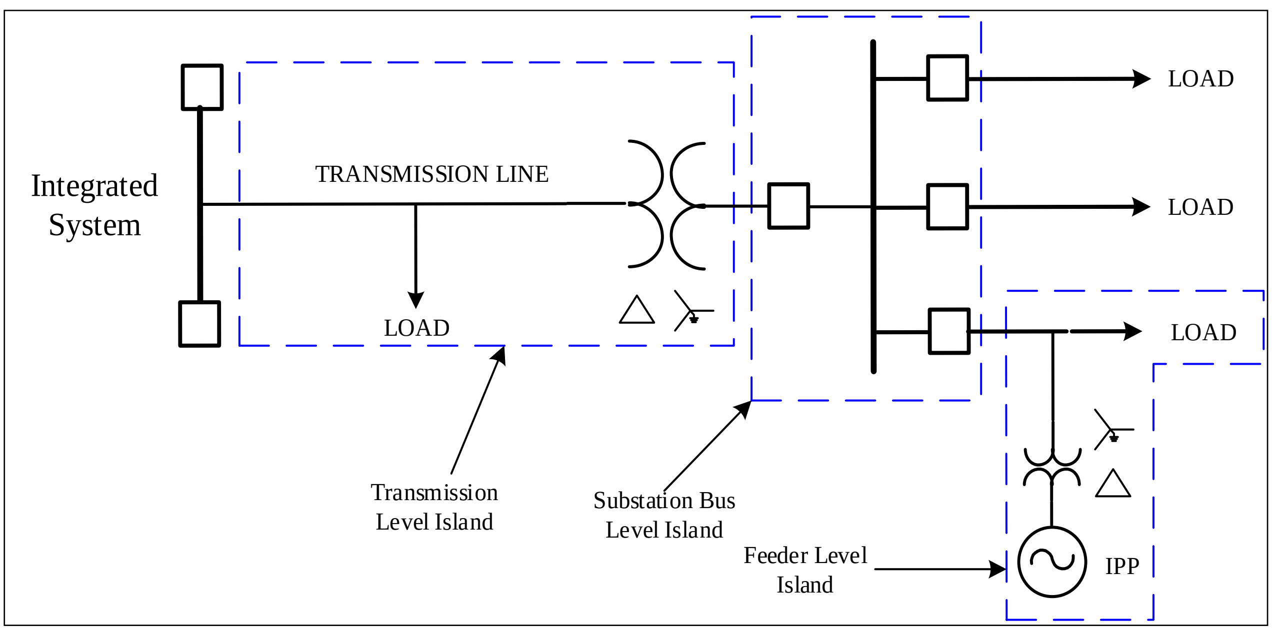

Figure 1: Different Types of Islands

Technical Challenges

a) Protection Challenges: When operating as a Microgrid, the local generation may not be able to produce enough short circuit fault current. Short circuit and protection coordination studies should be performed to assess and assure proper operation of protective devices. Alternative protection settings, which are significantly more sensitive than the traditional protection setting used in the integrated mode, are often required during Microgrid operation.

b) Loss of Utility Ground fault Sensitivity for Ground Faults: The substation protection covers for phase and ground faults up to first protective device on the feeder. High side wye and low side delta are preferred choices for DG entrance transformer [7]. With the high side grounded, the DG transformer is a source of ground fault current and de-sensitization of the utility ground relay can occur.

   BC Hydro distribution feeders are four-wire, three-phase with multi-grounded common neutral conductor [4]. Figure 2 shows a simplified one-line diagram of a distribution station, which is connected to transmission system via 130/25 kV delta-grounded wye substation transformer.

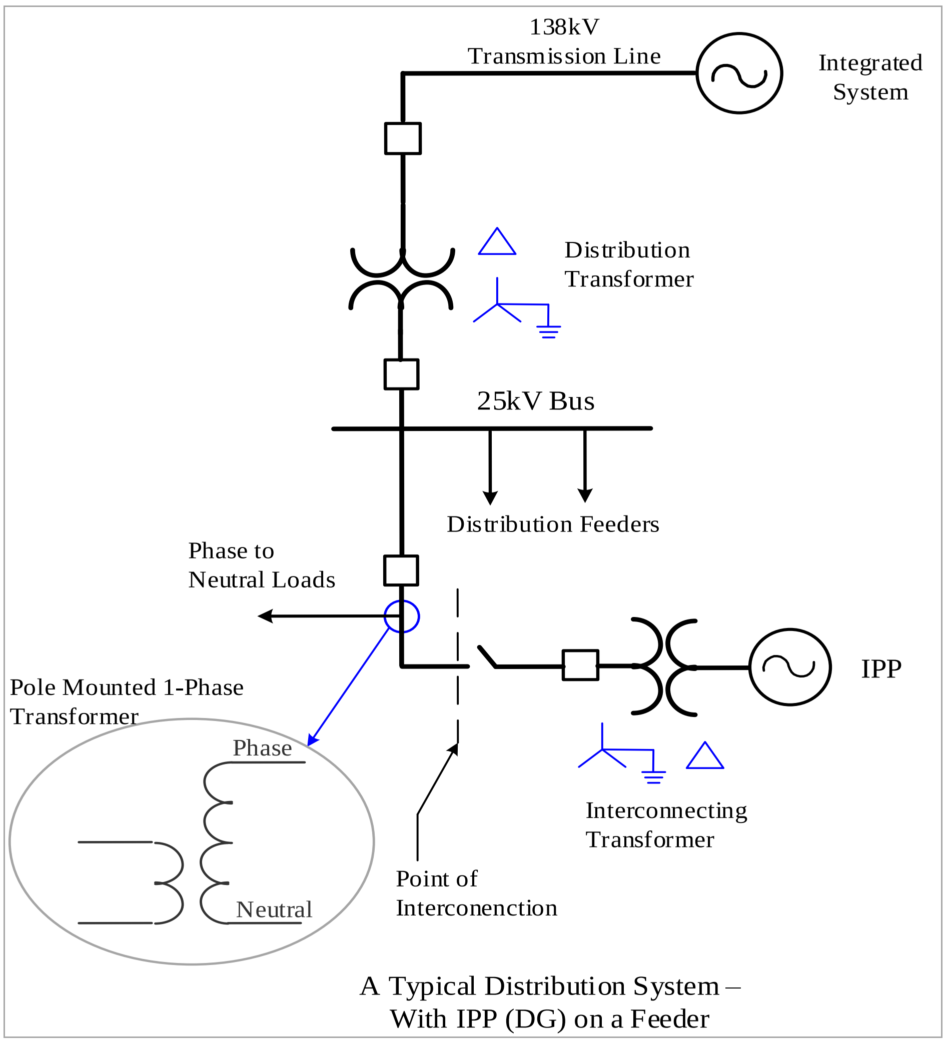

Figure 2: Typical Distribution Substation connected to Transmission System

The 25 kV or wye-side is solidly grounded at the substation. The fourth or neutral wire of each feeder has multiple-grounds, allowing single-phase loads to be connected between phase and neutral via pole and pad-mounted transformers that are rated for line-to-neutral voltage. Also shown in the figure is a DG connected to a feeder via an interconnecting transformer having traditional generator-unit transformer configuration; the low-voltage (or DG) side is delta and the 25 kV or distribution feeder side is connected grounded-wye. A solidly grounded DG interconnecting transformer can reduce the sensitivity of the feeder ground protection to an unacceptable level. Interconnecting with a delta configuration on the 25 kV side avoids ground protection desensitization completely but leads to an ungrounded system during Microgrid operation. So as a compromise, reactance grounding can be used on the feeder side.

c) Risk of Utility and distributed generation out-of-synchronism close

Refer to Figure 2, closing of any substation or transmission breaker while DG is still connected poses risk of an out-of-synchronism close

d) Risk of temporary or sustained overvoltage

Refer to Figure 2, where a DG connected to the utility system via an ungrounded interconnecting transformer (transformer with delta winding on the 25 kV side instead of wye-ground as shown) can expose the utility and its customers to unacceptable high voltages during ground faults. During ground faults, an ungrounded DG in a Microgrid subjects pole mounted signal-phase transformers to line voltage and severely saturates them or can damage them.

e) Coordination for adjacent feeder faults

The feeder protection on the DG feeder may mis-coordinate for a fault on an adjacent feeder, as illustrated in Figure 3. One solution for this is to directionalize the Utility feeder protection.

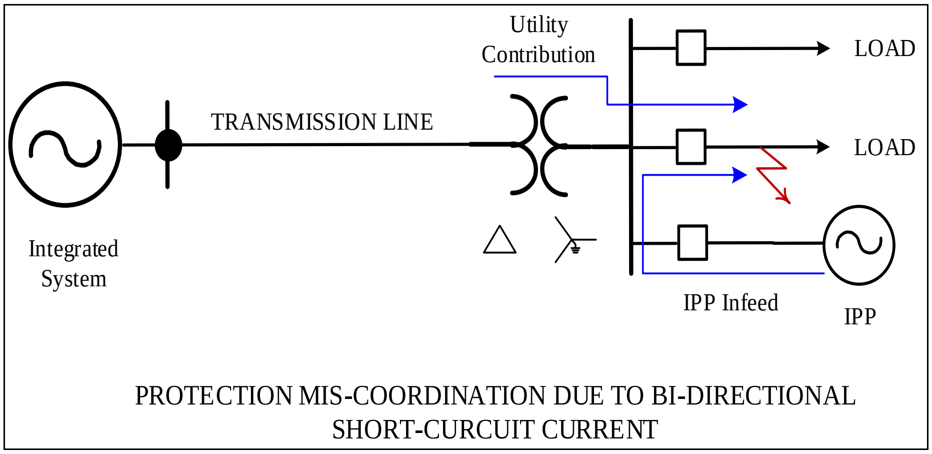

Figure 3: Coordination Issue due to DG Infeed

f) Bi-directional power flow through feeder voltage regulators and transformers leads to incorrect operation of on-line tap-changers, which in turn affects voltage regulation

g) Power Quality: Microgrids with inadequate short circuit strength, low-inertia generators and without high-speed governors can have challenges maintaining voltage and frequency within Power Quality standards.

h) Stability: Low rotational inertia within a Microgrid can introduce operating challenges.

i) Black Start Capability: Special black start procedures are required to avoid risk of safety or equipment damage

j) Compliance with Standards: IEEE 1547: Microgrid design may require compliance to local or IEEE-1547, Interconnecting Distribution Resources with Electric Power System.

5. Description of Distribution System

The distribution substation, DXX, is a town in Central British Columbia located close to the Alberta border. Unlike much of the rest of the BC Hydro system, this area relies on a single 138 kV radial transmission line that crosses several hundred kilometers of forest and mountainous terrain where repairs can be difficult, and the risk of outages is relatively high. Figure 4 shows the 138 kV transmission system that serves DXX substation.

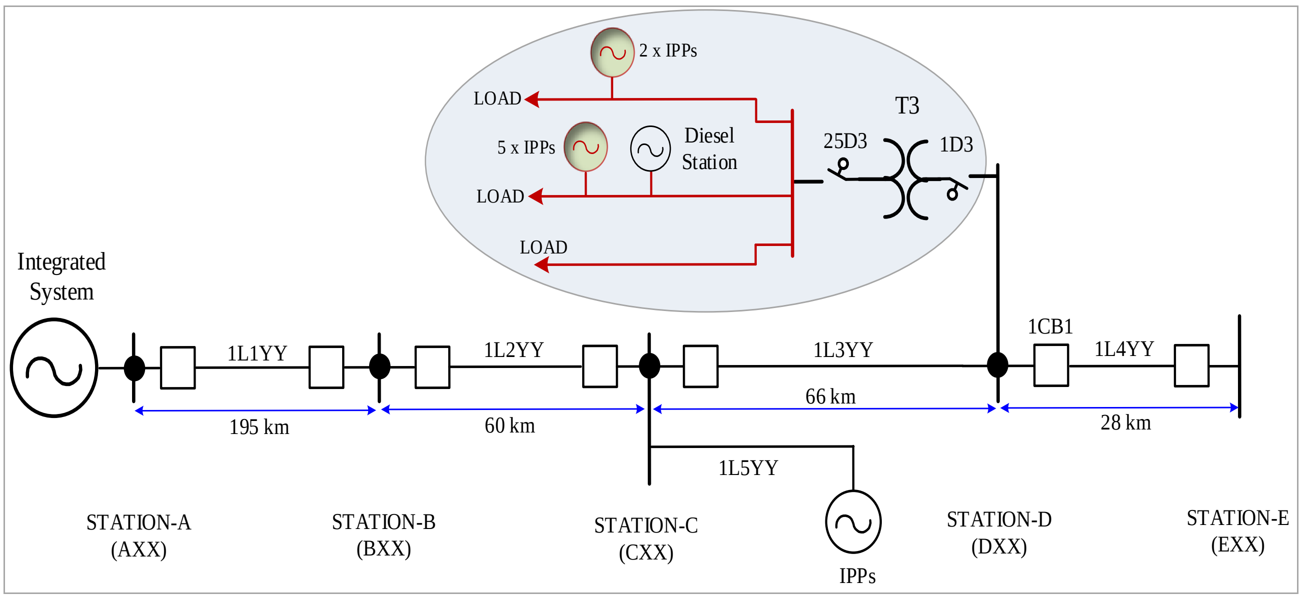

Figure 4: Area One Line Diagram

Refer to Figure 5 for a more detailed DXX substation configuration which consists of a 138/25 kV step down substation supplying three radial feeders. DXX has one step down transformer (T3) with a fully forced rating of 18.8 MVA. The transformer has a high side circuit switcher (1D3) and low side disconnect switch (25D3) for isolation. DXX 25 kV is a self-contained GIS module that has two incoming 25 kV bus breakers (25CB1 & 25CB2), one main bus (25B1), one transfer bus (25B2) and four outgoing breakers (25CB51-54). DXX substation is also equipped with two 25 kV distribution capacitor banks, 2.4 MVAR each.

The substation was originally designed as a traditional distribution substation, for unidirectional power flow only. Over the years, two of the three feeders received several run-of-the-river distributed generators as follows:

<u>Feeder-51:</u> The feeder has:

- Two run-of-the river hydro-electric distributed generators: IPP6 and IPP7
- Two field controlled reclosers equipped remote SCADA controllability from control room

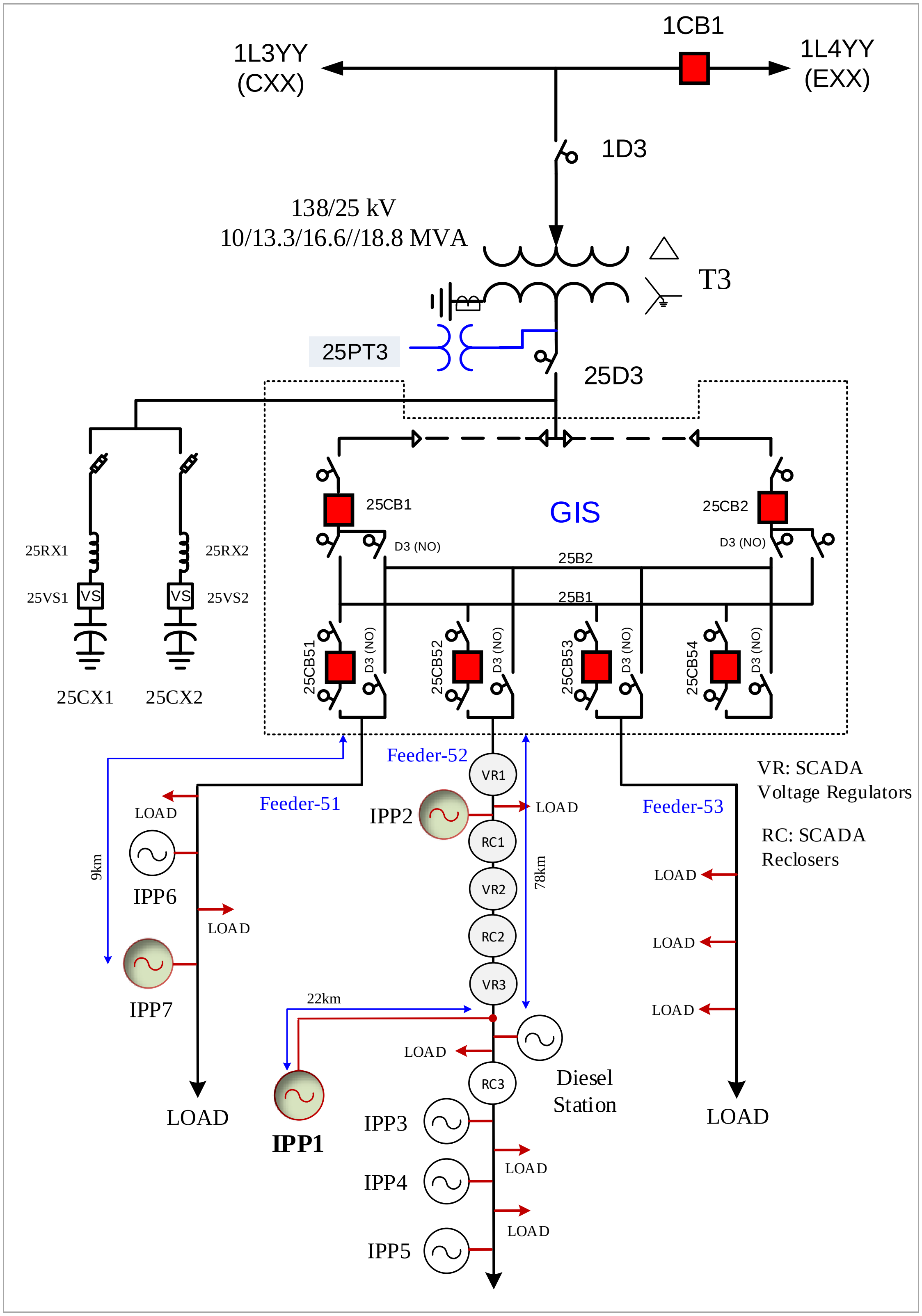

Figure 5: DXX Substation and Distribution Area One Line Diagram

Feeder-52: The feeder has:

- Five run-of-the river hydro-electric distributed generators: IPP1 to IPP5.
- Two distribution SCADA controlled voltage regulators
- Five distribution SCADA controlled switch and reclosers
- Diesel generators located in a community approximately 85 km along the feeder. The feeder has long overhead line with most customers connected at the end of line. Until recently BC Hydro owned diesel generators located near the customers were used as sole backup supply system

Feeder-53:

- Feeder-53 has load only and no generation.

Table-1 lists all distributed generators (IPP1 to IPP7) along with their ratings, physical locations on the distribution feeders and grounding on the feeder (25 kV) side.

Feeder Designation	**Name**	**Number of Units**	**MVA Rating**	**Transformer grounding on the feeder**	**Distance from DXX Substation, km**
FEEDER-51	IPP6	1	0.003	Ungrounded	7.5
	IPP7	2	2.85	Reactance	9
FEEDER-52	IPP2	1	3.75	Reactance	29
	IPP1 (MASTER HYDRO PLANT)	2	5.00	Solid	Tap 78 km from DXX & generation 22 km from tap
	IPP3	2	1.200	Ungrounded	104
	IPP4	3	1.600	Ungrounded	112
	IPP5	3	4.000	Ungrounded	
	Diesel Station	3	0.60	Ungrounded	

Table-1: DXX Distribution IPP Description – (IPP6 is a single-phase micro-hydro)

6. DXX Substation Limitation

DXX substation is radially fed from the integrated system via a single path comprising of three 138 kV transmission lines in series: 1L1YY, 1L2YY and 1L3YY. The transmission path has a history of forced and planned outages. BC Hydro does not use overhead shield wires and the lines are subjected to lightning faults during the short lightning season. Beside lightning, forced outages are caused by pole fires, broken wishbone, damaged cross arm, transmission structure failure etc. Planned outages can be due to maintenance work, like work on substation transformer, transformer load tap changer (LTC), station disconnect/isolation switches (1D3 and 25D3), transmission poles etc. During these incidents, the DXX customers are without power. Appendix I gives a summary of forced and planned outages for the area transmission lines 1L1YY, 1L2YY, 1L3YY and DXX T3. To minimize customer outages, it was decided to make of use distributed generation at DXX to maintain customer supply during transmission path outages. However, the following substation issues were identified while studying islanded operation with local generation:

- Distribution 25 kV station capacitor banks are used for the VAR control but the Operator has no visibility or ability to control the capacitor bank circuit breakers

- Long transmission lines and long distribution feeders result in voltage degradation on the transmission level as well as along the distribution feeders. Under normal system operation, DXX is normally operated at higher voltage on the transmission level
- A synchroscope is not installed at DXX substation 25 kV bus for reconnecting island substation back to the integrated system
- There is no remote control or visibility of some local generation. In the absence of indication for the supporting generating plants, the Operator has to rely upon phone conversations with individual plant operators
- There is no remote metering and logging of local generation. In the absence of metering data for all the generating plants, Operations Planning relies on some estimation, historical data, phone conversations with individual plant operators to estimate and calculate actual substation load and actual generation from all of the plants. In absence of remote metering, revenue metering and PQ meters on most of the plants are used as data sources

7. Microgrid Solution

To reduce customer outages and the carbon footprint, BC Hydro explored use of renewable (run-of-the-river) generation as much as possible to service the station loads for planned transmission outages and in response to sustained forced outages of the transmission supply. Based on Engineering selected criteria, i.e. generation capability, automated modern governor control system, available inertia capacity, location of the generating plant and power quality (PQ) performance of the distribution circuits during islanded operation, three run-of-the-river plants were selected: IPP1, IPP2 and IPP7. IPP1 was selected as the master plant to run in an isochronous mode i.e. zero droop - voltage and frequency control to follow load during islanded operation. The other two generating plants (IPP2 and IPP7) support the master plant from a PQ and reliability performance perspective while in Microgrid mode. They run under fixed kW output. BC Hydro and the generators owners worked together to identify and implement the plant control modifications allowing for the islanded operation.

IPP1:

The plant has two identical generators with total plant capacity 10 MVA. The plant design was modified for islanding service. The original design had flywheels to provide inertia for islanding, but when commissioning for integrated mode (grid-connected) operation, it was noticed that long distribution lines caused phase shifts leading to loss of synchronization of the IPP1 generators as the high inertia turbines could not swing quickly enough but they also did not have enough stored energy to prevent the phase shifts. The original flywheels were sized to maximize the capacity of the generators to pick up load for islanding, but since the original design, a high-speed governor was implemented that can operate fast enough that inertial support is not required.

IPP1 has two double jet Pelton turbines direct connected to 600 rpm generators. The water injector jets are fitted with deflecting blades that can divert a portion of the water flow away from the turbine runner, thereby modulating the power output of the turbine. The jet controls must be operated relatively slowly to avoid pressure spikes in the penstock, and to prevent excessively rapid changes in the stream depths. The deflectors can be operated very quickly, with full 0-100% operation in either direction possible in 0.1 seconds. Actual movement during load acceptance or rejection require only a portion of the deflector's movement, so the response can be very fast. The plant owners designed a control system which is capable of taking advantage of the very high speed deflector control element while avoiding instability due to high governor gains. During the extreme changes in load, the control will reach full stroke, which does lead to some overshoot in control; however, it decays rapidly to reach nominal frequency. During smaller load changes, the control remains in its effective range, and there is generally no overshoot.

Prior to use in islanding mode within the Microgrid, IPP1 was tested extensively with a 4.6 MW load bank. The two turbines were synchronized together, and then the circuit breaker at the Point of Interconnection (POI) is closed to accept the load. The load bank was situated at the POI to the BC Hydro system. High-speed governor and exciter responses were tested to sudden load changes in the islanded operation. To simulate the full load pick up and rejection, the water jets of the turbines were adjusted to produce maximum plant output, with the deflectors maintaining speed-no-load for 60 Hz. The IPP1 POI circuit breaker was closed onto the load bank with it set to its maximum load of 4.6 MW. After voltage and frequency were observed to be stable, the circuit breaker was opened, causing full load rejection operation of the governor. Figure 6 and 7 show the plant frequency and voltage responses to step load changes, respectively. On load application, the plant frequency dropped down to 57 Hz, returned to 60 Hz in about 6 second and then overshot to 61.4 Hz. It finally stabilized completely within 12 seconds. The voltage dropped to 97% of nominal on the initial load acceptance. Load rejection resulted in the frequency reaching 62.7 Hz momentarily. Although this frequency exceeds the BC Hydro PQ settings, it only occurs after total loss of the customer load, so has no risk to the customers. Voltage spike was less than 2%. The plant operated as expected. Frequency and voltage excursions were within acceptable range for the islanded operation, and actually were within normal BC Hydro parallel operations PQ limits.

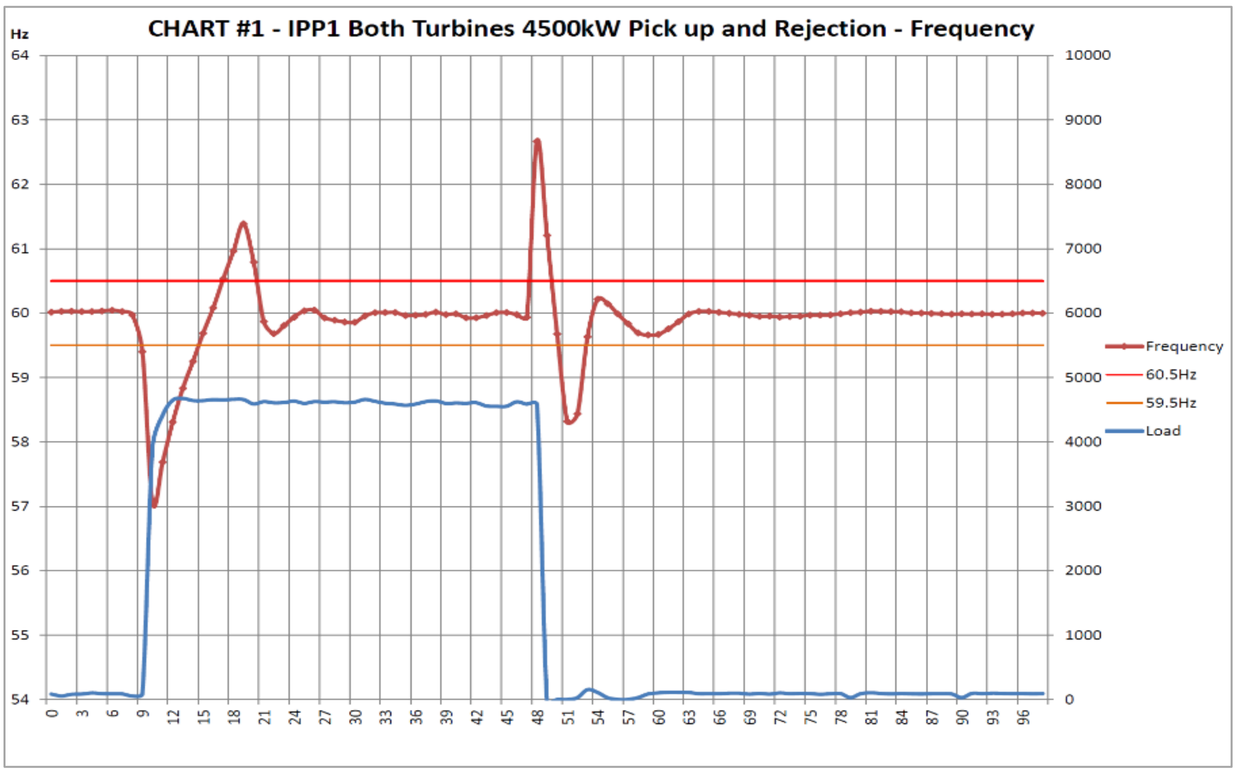

Figure 6: IPP1 plant frequency response on sudden load pick-up and rejection

IPP2:

This plant is assigned to provide kW and voltage support during islanding events. When participating in islanded operation, the kW output is set manually as required to manage the load so that IPP1 has adequate governing range. IPP2 has strong voltage control that provides support to maintain voltage at the DXX end of the distribution feeder, Feeder-51.

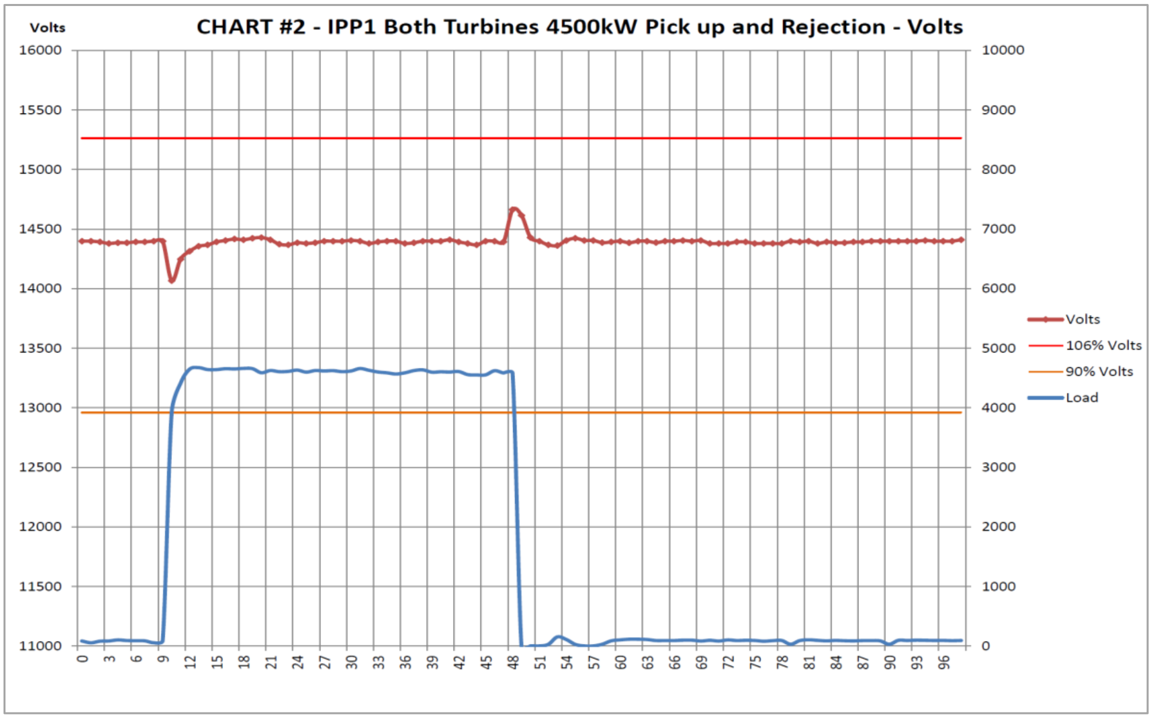

Figure 7: IPP1 plant voltage response on sudden load pick-up and rejection

<u>*IPP7*</u>:

This plant is assigned to provide kW and voltage support during islanding events. IPP7 provides adequate voltage support to maintain voltage at the DXX end of the distribution feeder, Feeder-52.

<u>*Microgrid Grounding:*</u>

The unit transformer on IPP1 is delta-wye with solid grounding on the feeder (25 kV) side. The solid grounding of IPP1 provides effective grounding in Microgrid operation. However, the ground protection at IPP1 is set very sensitively which removes the generators quickly after ground faults, which in turn eliminates the ground protection desensitization of station feeder protection during the grid-connect operation.

The unit transformers on IPP2 and IPP7 are also delta-wye but are reactance grounded. Because IPP2 and IIP7 can't independently supply loads, they pose no risk of overvoltage in Microgrid and do not de-sensitize the station feeder ground protection during their grid-connected operation.

<u>*Microgrid Control:*</u>

The operator of IPP1 has access and permission from the owners of the IPP2 and IPP7 involved in the island to operate their plants as needed to support the island. The operator has SCADA access to all the plants, so is in a good position to monitor available water, load, and voltage parameters and adjust each plant as needed. Although this works in the BC Hydro example case, it is unlikely that most similar networks would have this capability. In the general case, the utility load desk should have full SCADA visibility of the participating IPP's key operating data, including water availability. In the absence of SCADA signals for these parameters, the load desk would have to direct each IPP via telephone for setting the correct power output to ensure the primary plant maintains a good range of governing capacity.

All the IPPs designated for islanding service have black-start capability, but only IPP1 is required to actually black-start. The other IPPs do not need to start prior to their feeder being energized by the island.

BC Hydro installed distribution automation devices (reclosers, switches, voltage regulators) with full SCADA control at strategic locations for sectionalizing to meet load pick up and reliability performance during Microgrid operation. These automation devices are configured for bidirectional power flow.

The diesel generating plant was assigned as backup source when DG is not available in winter season due to reduction in river water flows.

7.1. DG Availability

- During spring, summer and fall months, typically all the generators have enough water availability with full generation capabilities. Total distributed generation exceeds DXX load for 8 months of the year.
- From system power flow perspective, DG generation back feeds into the transmission system.
- Based on load and DG resource balancing, during 8 months of the year, typically station load on average is about 4 MW and generation from the chosen generators (IPP1, 2 and 7) is about 10 MW.
- As an added benefit of Microgrid, BC Hydro is minimizing the use of diesel generation and deferring the capital investment in the area.

7.2. Voltage and Frequency Deviations Allowed

While operating as a substation island, i.e. supplying the distribution circuits and DXX substation bus up to station transformer disconnect switch 25D3, BC Hydro ensures that the Microgrid is still maintaining CSA power quality requirements and following BC Hydro Power Quality Guide [5].

7.3. Remote Metering, Indication and Control

This section lists the information that is available to BC Hydro Control Centers.

- DXX Substation SCADA Control and Indication:
    - The 25 kV bus circuit breakers (boundary between integrated system and Microgrid): 25CB1 & 25CB2
    - The four distribution feeder circuit breakers: 25CB51, 25CB52, 25CB53 & 25CB54
    - Load tap changer for station power transformer T3 (138/25 kV) (Auto/Manual as well as tap position control)
    - Power transformer isolating disconnect switches (1D3 and 25D3)
    - Normal and Alternative Feeder Protection Selector
    - DXX feeder PN alternate settings

- DXX Substation Remote Metering Quantities:
    - Station and individual feeder – Amps, Voltage, MW and MVAR
    - Station transformer metering
    - Station 25 kV bus voltage

- DXX Distribution Circuit SCADA Control Devices:
    - Seven distribution SCADA controlled switches and reclosers on two distribution circuits, Feeder-51 and Feeder-52

- Two distribution SCADA controlled voltage regulators on distribution circuit Feeder-52, which has master generating plant IPP1 (under Islanded configuration)

- DXX Distribution Circuit Remote Metering:
  - Distribution automation devices – Amps, Voltage, MW and MVAR

- BC Hydro Diesel Generating Plant (Full plant control)
  - Black start capability, generating mode, individual generator start/ stop, raise/ lower MW and MVAR
  - Point of delivery distribution SCADA recloser
  - Generation and point of delivery devices – Amps, Voltage, MW and MVAR, frequency

- Master generating plant, IPP1, indication only (no control):
  - Generating Plant mode,
  - MW, MVAR, Voltage, Frequency
  - Point of delivery circuit breaker status
  - Governor control mode (droop/isochronous modes)
  - Unit excitation setpoint

- Other supporting generating plants have no indication

8. Microgrid Operating Plan

This section describes planning steps: (a) how a sustainable island is formed on planned separation of DXX from the integrated system and (b) how the island is reconnected without loss of supply to customers after the planed outage work is over.

The Master Generating Plant (IPP1) has the capacity to pick up the entire DXX substation load from early May to late September. After determining DXX substation load, it is determined if other available area generation are required or not to support island.

<u>Transition to Microgrid</u>

The transition from grid-connected to islanded or Microgrid mode is designed only for the planned transmission outage i.e. in anticipation of maintenance work, storms, wildfires etc. Below is the procedure that is followed for the transition from Grid connected mode to Island Mode:

1. The Master Generating Plant (IPP1) is set in Co-gen (droop) mode. In this mode, BC Hydro controls Voltage and Frequency.
2. The MW and MVAR flow through substation transformer T3 are brought to ZERO by following the following steps:
   a) Step 1: By adjusting IPP1 MW output (Fixed MW Mode), ZERO MW flow across substation transformer T3 is achieved. When ZERO MW flows through T3, it implies that IPP1 and DXX load (MW) are balanced.
   b) Step 2: Put substation transformer T3 LTC in manual control mode. By adjusting substation transformer T3 LTC controller as well as support from distribution voltage regulators on feeders, ZERO MVAR flow across substation transformer T3 is made. The substation bus voltage is maintained above 23.5 kV.
3. Once the MW and MVAR flow through the substation transformer T3 are ZERO, the distribution substation DXX is Islanded by opening the main bus breakers 25CB1 and 25CB2.

4. After the Island is formed, the IPP1 mode is changed from Co-Gen (droop) to the island mode (isochronous mode – zero droop with voltage and frequency to follow load). At this stage, the IPP1 is carrying the entire DXX substation load
5. The distribution circuit breakers and recloser protection settings are changed to alternative settings – these are sensitive protection settings required in the Microgrid operation (discussed in Protection Section)
6. The IPP1 protection settings are changed to the island mode – these settings are set for wider frequency and voltage ranges required in the Microgrid operation (discussed in Protection Section)
7. In the Microgrid mode, the IPP1 controls voltage and frequency of the island.
8. If more generation is required to support, IPP2 and IPP7 can also be put in-service. These generating plants will operate in droop mode (constant generation – fixed kW output mode).
9. If the frequency is high and there is a need to reduce generation, the supporting IPP Generating Plants should be turned off or reduce generation.
10. Substation transformer T3 can be isolated by opening 1D3 and 25D3.

Re-connection to Grid:

After planned outage work is completed, the transition from Microgrid to integrated operation is performed as follows:

1. At DXX substation, transformer T3 is energized by closing 1D3 and 25D3. This energizes T3 low voltage side potential transformer 25VT3 (the breakers 25CB1 and 25CB2 open).
2. The voltage and frequency are noted on either side of the main substation bus.
3. To make voltage difference as close as possible to ZERO, transformer T3 taps are adjusted.
4. When BC Hydro is ready to restore service from the 138 kV transmission system, the frequency settings of the IPP1 Plant is increased slightly to 60.05 Hz to allow the system phase rotation to roll into synch with the BC Hydro Grid. This ensures that the frequency on either side of the main substation bus is almost identical and avoid tripping of distributed generators.
5. When the voltage difference and frequency slip across the bus breaker are within acceptable limits, bus breakers are closed.
6. Change IPP1 from Island mode to Co-gen (droop) mode for parallel operation.
7. Substation is now connected back to the integrated system.
8. When the BC Hydro transmission connection is made, the frequency returns to 60 Hz and the IPP1 gradually increases output to normal levels.

8.1. Operational Experience During Islanded Mode

1. Any outage on the distribution system, will trip off the master generation
2. Field operations will work to troubleshoot and isolate the fault
3. The load sectionalisation devices will be operated (OPEN) to make system ready
4. With master generation black start capability generation will start with partial load pick up
5. By operating sectionalisation devices master generation will pick up all the loads, if required supporting generator units will come on line in droop mode first

9. Protection Scheme: Existing and Modifications

The station and plant generator protections must be able to operate reliably in the grid-connected as well as in Microgrid operations. When operating in the Microgrid mode, the distributed generators may not provide enough fault current for the protection devices to detect and operate reliably. A detailed short circuit study was performed with DG operated in the grid-connected and in an islanded mode. Since

Microgrid is a relatively weak system, any disturbance due to faults on the distribution feeders generally trips the plant generators on Power Quality before overcurrent elements can operate.

Station Protection:

The existing distribution feeder protection is a multifunction overcurrent relay. The existing relay uses the following elements to provide feeder protection: phase inverse time and definite time overcurrent elements, negative sequence overcurrent elements, residual inverse time overcurrent elements, dead bus or synchronization check for circuit breaker closing, trip fail logic for breaker failure and auto-reclosing elements. Since the distribution substation (DXX) configuration changes significantly during the islanded operation, new protection settings had to be implemented to provide reliable fault coverage during islanded operation. This was very challenging due to protection coordination requirements with distribution level protection devices and low available fault levels during the islanded operation. Sample configuration which needs to be covered by the devices in the substation is shown in Figure 8. During this configuration, we would expect that Feeder-51 protection has a chance to operate first followed by Feeder-52 protection to ensure that only the faulted section of the system is isolated.

Upon restudy of the area, we settled on having two separate setting groups: standard setting for the grid-connected and alternative setting for Microgrid operations as shown in Table 2 and 3, respectively. The setting groups can be toggled between the two groups locally via pushbutton control or remotely via the control center. Protection sensitivity had to be increased significantly to accommodate for low short circuit current in Microgrid mode but it posed risk of mis-operation on cold-load pickups. To avoid cold load pick up trips, Feeder 51 and 52 breakers are opened from control room before restarting Microgrid after a station outage. Feeder 52 is also sectionalized by opening SCADA controlled field reclosers. After black starting IPP1, loads on Feeder 52 are restored in steps by closing of feeder reclosers followed by closing of feeder breakers. Depending on load vs generation other IPPs are resynchronized with IPP1.

Phase Settings	Phase Pickup	Curve	Time dial
Feeder-51[1]	408A	U3	3.50
Feeder-52[1]	408A	U3	3.50
Feeder-53	408A	U3	3.50
Ground Settings	Ground Pickup	Curve	Time dial
Feeder-51	240A	U4	6.50
Feeder-52	180A	U4	9.50
Feeder-53	240A	U4	6.50

Table-2: Standard Feeder Protection Setting in the grid-connected mode

Phase Settings	Phase Pickup	Curve	Time dial
Feeder-51[1]	74A	U4	0.70
Feeder-52[1]	84A	U3	1.8
Feeder-53	60A	U3	1
Ground Settings	Ground Pickup	Curve	Time dial
Feeder-51	38A	U4	3.5
Feeder-52	48A	U3	4
Feeder-53	24A	U4	3.5

[1] The elements are torque controlled by undervoltage phase-to-phase elements

Table-3: Sensitive Feeder Protection Setting for Islanded or Microgrid Operation

Furthermore, we added new coordinated frequency protection which will trip Feeder-53 first, then Feeder-51 and finally Feeder-52. It is because Feeder-53 carries the smallest load and Feeder-51 carries the most load. The settings for the frequency protection are shown in the Table 4 below.

Frequency Elements	Frequency element pickup	Frequency element delay
Feeder-51	58.5 Hz	1200 cycles
Feeder-52	Not used	
Feeder-53	58.8 Hz	600 cycles

Table-4: Coordinated Frequency Protection Settings

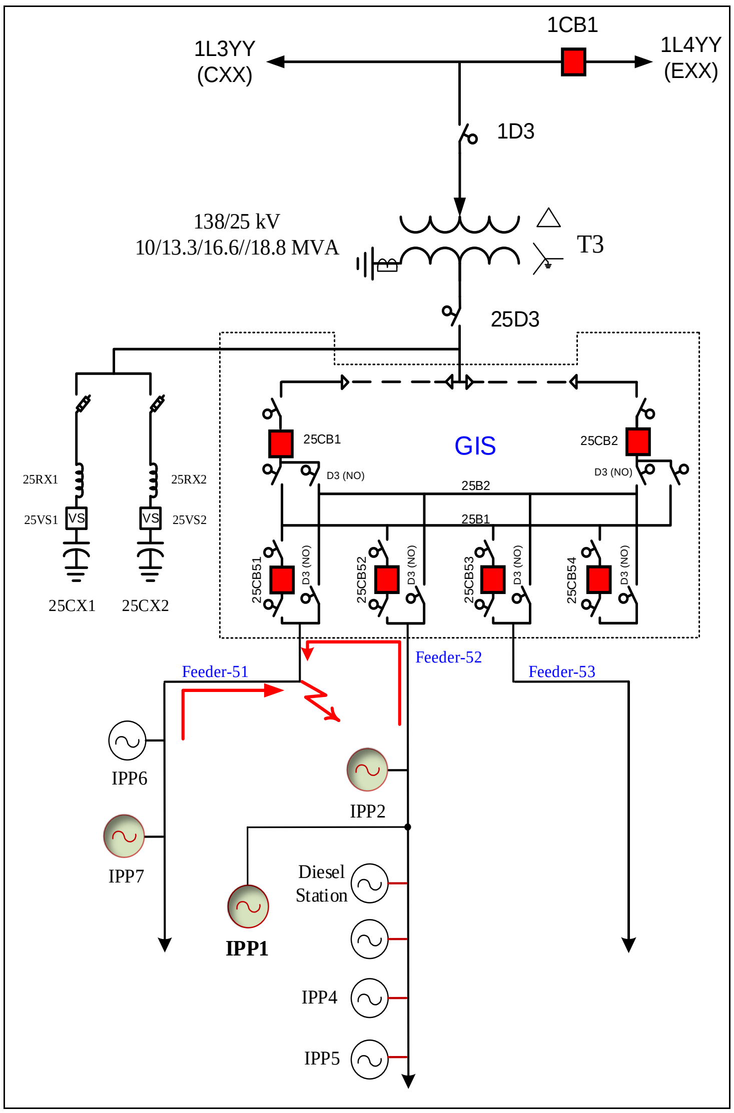

Figure 8: DXX Substation Protection Challenges

Finally, we also added dead line and synch check feeder breaker closing supervision on breakers 25CB51 and 25CB52. These elements were added to facilitate restoration of the system without causing unnecessary customer outages.

Phase Settings	Maximum angle (degrees)	Maximum slip frequency (Hz)	High voltage threshold for healthy voltage window (V sec)	Low voltage threshold for healthy voltage window (V sec)	Breaker close time for angle compensate (cycles)
Feeder-51	20	0.25	78.56 (110% Vnom)	65.50 (90% Vnom)	3.66
Feeder-52	20	0.25	78.56	65.50	3.66
Feeder-53	No synch check				

Table-5: Dead Line and Synch Check Function Settings

Plant PQ Protection:

BC Hydro uses tight PQ trip settings on distribution generators [4,5] to avoid unplanned sustainable islanding of generators with loads. A Microgrid is a weak electrical system and standard PQ settings can cause tripping of the plant generators for disturbances due to faults on the distribution feeders. Thus, the master IPP1 is switched to alternate wider PQ settings in the islanded mode. No alternate settings are used for the two plants IPP2 and IPP7 because IPP1 can support the entire substation load.

IPP1 Power Quality Settings:

The plant PQ settings are tabulated below.

UNDERFREQUENCY SETTING (HZ)			
GRID-CONNECTED		ISLAND MODE	
SETTING (HZ)	MINIMUM TIME (SEC)	SETTING (HZ))	MINIMUM TIME (SEC)
59.40	180	59.40	600
58.40	30	58.40	60
57.80	7.50		
57.40	0.71	57.40	10
56.80	0.08		
56.40	INSTANTANEOUS		
53.00		53.00	INSTANTANEOUS

OVERFREQUENCY SETTING (HZ)			
GRID-CONNECTED		ISLAND MODE	
SETTING (HZ)	MINIMUM TIME (SEC)	SETTING (HZ)	MINIMUM TIME (SEC)
60.60	180	60.60	600
61.60	30	61.60	60
61.70	INSTANTANEOUS		
		62.60	10
		67.00	INSTANTANEOUS

Table-6: IPP1 Under and Over Frequency Trip Settings in Grid-Connected and Islanded modes

UNDERVOLTAGE SETTING (VOL)		
GRID-CONNECTED		ISLAND MODE
UNDERVOLTAGE LIMIT	MINIMUM TIME (SEC)	MINIMUM TIME (SEC)
V < 50%	0.12	0.12
V < 85%		4.75
V < 90%	1.96	59.75
90%< V < 106%	CONTINUOUS	CONTINUOUS

OVERVOLTAGE SETTING (VOL)		
GRID-CONNECTED		ISLAND MODE
OVERVOLTAGE LIMIT	MINIMUM TIME (SEC)	MINIMUM TIME (SEC)
90%< V < 106%	CONTINUOUS	CONTINUOUS
V > 106%	0.96	59.75
V > 110%		4.75
V > 120%	1.96	0.12

* Voltage operation between 90% and 106% of Nominal voltage is considered normal and trip should not occur

Table-7: IPP1 Under and Over Voltage Trip Settings in Grid-Connected and Islanded modes

<u>IPP2 Power Quality Settings:</u>

The plant PQ settings are tabulated below.

VOLTAGE SETTINGS (VOL)	
	MINIMUM TIME (SEC)
V < 50%	0.160
V < 90%	2.00
90%< V < 106%	CONTINUOUS
V > 106%	120
V > 110%	
V > 120%	0.160

FREQUENCY SETTINGS (HZ)	
	MINIMUM TIME (SEC)
F < 56.4	INSTANTANEOUS
F < 56.8	0.120
F < 57.3	0.750
F < 57.8	7.50
F < 58.4	30
F < 59.4 < 60.4	NORMAL
F > 60.6	180
F > 61.6	30
F > 61.7	INSTANTANEOUS

Table-8: IPP2 Power Quality Settings

<u>IPP7 Power Quality Settings:</u>

The plant PQ settings are tabulated below.

VOLTAGE SETTINGS (VOL)	
	MINIMUM TIME (SEC)
V < 50%	0.100
V < 90%	1.90
90%< V < 106%	CONTINUOUS

V > 106%	120
V > 110%	1.0
V > 120%	0.10

FREQUENCY SETTINGS (HZ)	
	MINIMUM TIME (SEC)
F < 56.4	INSTANTANEOUS
F < 56.8	0.040
F < 57.4	0.670
F < 57.8	7.50
F < 58.4	30
F < 59.4 < 60.4	NORMAL
F > 60.6	180
F > 61.6	30
F > 61.7	INSTANTANEOUS

Table-9: IPP7 Power Quality Settings

10. Lessons Learned

Despite elaborate and careful planning, sometimes things don't go as planned. This section will list two events where load was tripped.

Event-1: Partial Load Trip after Formation of Island

To work on substation transformer T3, it was required to isolate this transformer. For this, DXX substation bus breakers (25CB1 and 25CB2) were opened and the load was supplied by local generation. BC Hydro Control Center needed to isolate substation transformer T3 by opening 1D3 and 25D3. It is to be noted that BC Hydro Control Centers have no visibility or control for the two 25 kV Distribution Capacitor banks. Before isolating T3, Control Center Load Desk Operator verified verbally with the Field Electrician to confirm status of capacitor bank circuit breakers and was informed that both the capacitor banks are out-of-service, when in fact they were energized. Refer to Figure 9, which shows that the capacitor banks were drawing approximately 126A at 25 kV.

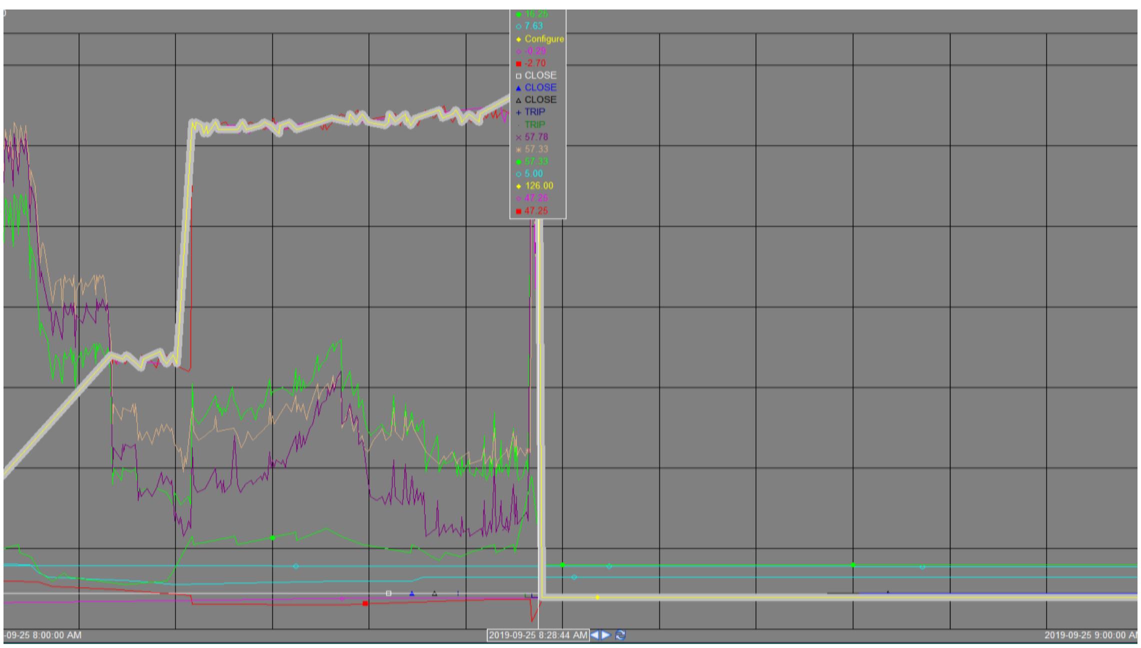

Figure 9: DXX Distribution Capacitor Bank Current 126A

This load was not seen in the bus telemetry used to verify the 0 MW/0 MVAR precondition for islanding. In this instance, the Control Center Operator used 25D3 to isolate T3. This disconnect was not rated for capacitor bank de-energization and flashed over. This appeared as a Phase B-C fault to transformer differential protection, refer to Figure 10. The transformer differential protection scheme is designed to trip for any fault current contribution from either high or low voltage side, and, tripped the IPP feeder circuit breakers (Feeder-51 and Feeder-52). Fortunately, when the substation bus breakers were tripped, not all the load was lost. The load connected to Feeder-52 that was supplied by IPP1 was able to stay connected, while the load connected to Feeder-51 was dropped. To pick up the load again, IPP1 was set to ensure it had adequate governing range and then the BC Hydro Control Center closed the substation breaker 25CB52 to back energize substation 25 kV bus and after that other substation feeders were picked one by one.

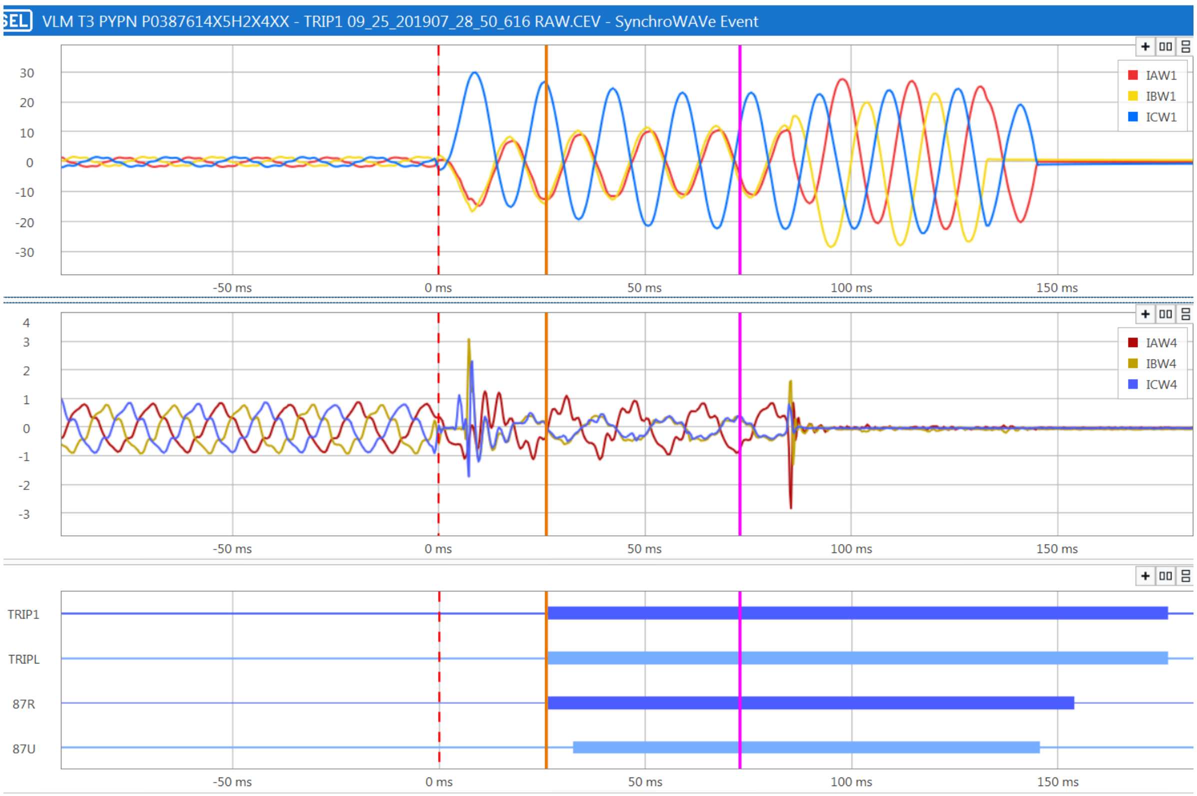

Figure 10: DXX Transformer T3 Differential Protection Trip

Event-2: Undesirable IPP1 Trip When Operating In an Islanded Mode

During an unusually long islanding event, one of IPP1's generators tripped due to a mis-programmed alarm. The second unit was unable to carry the load alone, and the IPP1 POI circuit breaker opened on under-frequency. In order to restore service to the customers as quickly as possible, a step by step approach of energizing a portion of the system with another IPP in it, and then bringing that IPP online to supply kilowatts so that the next area can be brought online. With IPPs 2 and 7 at speed-no-load (SNL), IPP1 was started and successfully energized all of Feeder-52 load. IPP2 is within this area, so it was brought up to its fully available capacity. This provided the single generator at IPP1 with enough range to accept several MW of further load. BC Hydro Load desk Operators switched field reclosers on Feeder-51 to bring on sections with the shortest path to IPP7. Once the IPP7 generator was energized, it was brought up to sufficient capacity to provide IPP1 with governing margin to pick up the rest of the loads, including Feeder-53.

Once the cause of the outage on the IPP1 generator was determined and corrected, the second unit was brought online to provide additional reserve, although it was not needed for the rest of the islanding operation.

This technique of bringing loads and generation online in stepwise fashion is applicable to any system that has sufficient distributed generation available to carry the load in its area, while using a single generator to control the system balancing. The distributed generators also provide multiple points of voltage support so that areas do not suffer from unusually high or low voltages throughout the system. This is especially important in such a long system, as it is normally configured to pass load in the opposite direction. It may not have capacity to boost voltage at the end typically controlled by the substation grid source, so the generators in that area can regulate the voltage when the substation cannot.

Figure-11 shows IPP1 the entrance protection relay tripping the POI Circuit Breaker after the frequency dropped to 52.9 Hz. The duration of the overall event was less than 500 ms.

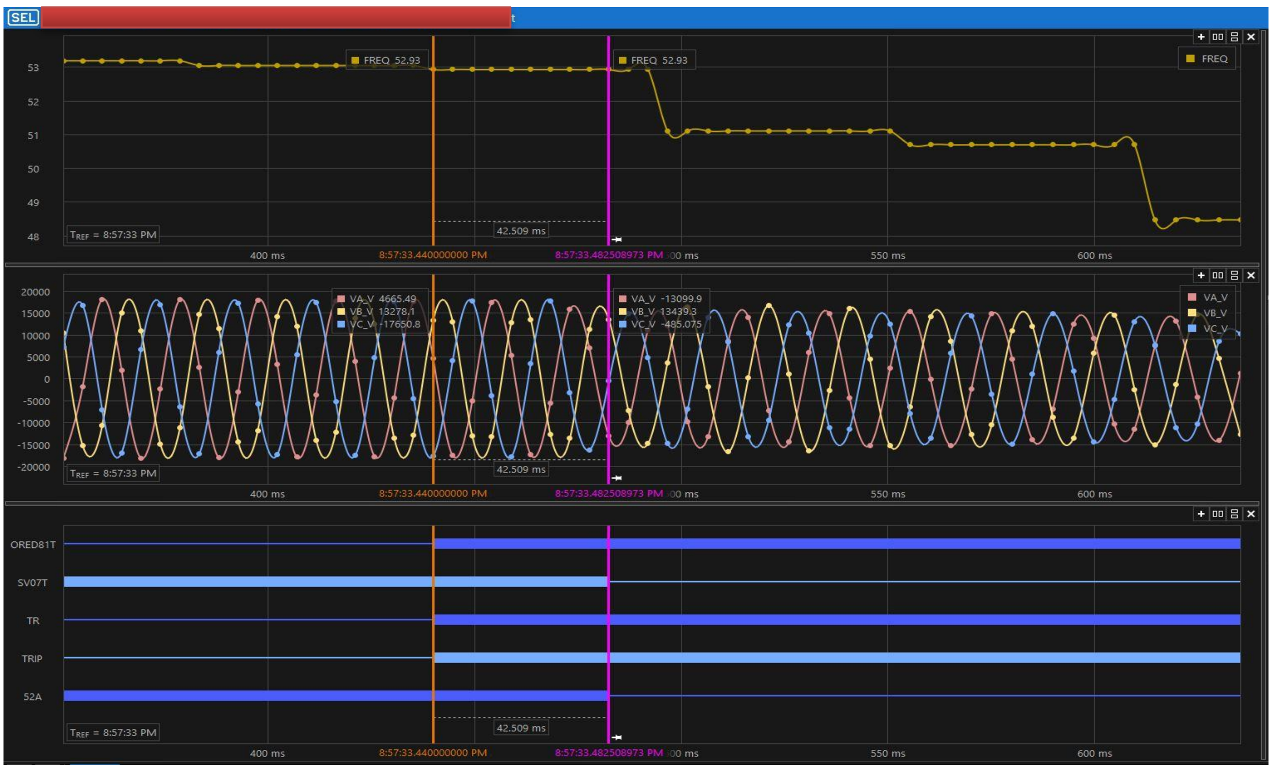

Figure 11: IPP1 Trip on Loss of one unit

11. Summary

1. Local generation and Microgrid deferred capital investment required for the capacity and reliability improvement of DXX. BC Hydro can maintain or improve customer satisfaction for the area.

2. Typically, on average three events (two planned events and one forced event) during the year.

3. Water resources availability for the local generation in the area during November to March due to freezing temperatures and cold winter months. During summer months April to August, all the local generating plants in the area have much more water resources; as a result the excess power is sent to grid.

4. BC Hydro diesel generating plant (November to February) generation is available whenever the local generation isn't sufficient to supply customers. In conjunction with all the available local generation the customers get supplied during outage conditions.

5. To make and execute the islanding plan, there is a fair bit of work involved from BC Hydro Scheduling Group, planning and control room. Once the Microgrid island is established, BC Hydro has full visibility of the master hydro run of river IPP1 (March to October) and full visibility and control for the diesel generating plant (November to February)

6. With the support of existing SCADA devices, BC Hydro is in a position to establish the Microgrid island remotely. For IPP1 generating plant (March to October) BC Hydro coordinates with the local generation to establish the Microgrid island remotely. Once the Microgrid island is established, BC Hydro has full visibility of IPP1 (March to October) and full visibility and control for diesel generating plant (November to February)

12. Conclusion

A traditional distribution station designed for unidirectional power flow can evolve into a bi-directional power flow substation. The transition can occur over a time as more and more distributed generation is added locally at the substation. Feeder, station and line protection upgrades are required to accommodate as the local generation increases. Different feeder protection and generator PQ protection settings groups are required to achieve reliable protection performance for allowing generation to operate in grid-connected and islanded modes. Highly sensitive feeder protection feeder settings in Microgrid operation are necessary for dependable operation and highly sensitive PQ settings in grid-connected operation are required to prevent unplanned formation of sustainable island. Sensitive feeder protection settings in Microgrid mode require cold load pick up management after Microgrid outages.

Unlike university or a research Microgrid, the paper shared challenges and experience with a utility distribution substation that can operate as a Microgrid and contributes to customer reliability while reducing the carbon footprint.

13. References

1. *NERC- Distributed Energy Resources, Connection Modelling and Reliability Considerations, February 2017*
2. *IEEE Standards Coordination Committee 21, "1547.4.2011 IEEE Guide for Design, Operation, and Integration of Distributed Resource Island Systems with Electric Power Systems," 2011.*
3. *Distribution Power Generator Islanding Guidelines, BC Hydro June 2006*

4. *BC Hydro Interconnection Requirements for Power Generators, June 2004.*
5. *BC Hydro Power Quality Guide, June 2005.*
6. *NERC Reliability Standard PRC-024-1, Generator Frequency and Voltage Relay Settings.*
7. *IEEE Standards Coordination Committee 21, "1547.2.2008 IEEE Application Guide for IEEE Standard for Interconnecting DR with EPS," 2008.*

Appendix I: Forced and Planned Outage by year – From 2000 till 2020

	2000 to 2005	2006 to 2010	2011 to 2015	2016 to 2020	Grand Total
Forced Outages					
1L1YY					
Sum of Event duration in Min	39074	774	1267	68	41183
Count of outage	19	9	11	14	53
1L2YY					
Sum of Event duration in Min	31940	3331	1314	433	37018
Count of outage	19	21	19	18	77
1L3YY					
Sum of Event duration in Min			2011	534	2545
Count of outage			21	23	44
DXX T3					
Sum of Event duration in Min	193		14	7897	8104
Count of outage	2		1	2	5
Sum of forced outage in Min	71207	4105	4606	8932	88850
Number of Forced outages	40	30	52	57	179
Planned Outages					
1L1YY					
Sum of Event duration in Min	14027	277	651	12847	27802
Count of outage	2	2	3	6	13
1L2YY					
Sum of Event duration in Min	11	9107	581	787	10486
Count of outage	1	5	2	4	12
1L3YY					
Sum of Event duration in Min			3977	2136	6113
Count of outage			2	5	7
DXX T3					
Sum of Event duration in Min	114	464	30543	1717	32838
Count of outage	1	3	4	4	12
Sum of Planned Outage duration in Min	14152	9848	35752	17487	77239
Number of forced outages	4	10	11	19	44
Total outage duration in Min	85359	13953	40358	26419	166089
Total Number of outages	**44**	**40**	**63**	**76**	**223**