

Planned Islanding of 8.6 MVA IPP for BC Hydro System Reliability

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I. Introduction

Recently, due to concerns regarding power quality and reliability of service, along with the development of numerous distributed generation resources, a different philosophy regarding the architecture of the power grid has been suggested. A MicroGrid is an area of the power system that has a large concentration of distributed generators (DG) among various loads [1]. What makes this system unique is that it is able to operate either in parallel with or disconnected from the power system. This type of grid paradigm is particularly interesting in terms of the technical, reliability and economic implications.

The MicroGrid satisfies criteria in order to serve both the power system (or MacroGrid) as well as the local loads. The MicroGrid may operate as an isolated power system which is able to supply all of the technical requirements of the loads. It can also be connected to the power system and therefore may supply excess power to the system under light local loads or may draw power during peaks. From the grid point of view, the MicroGrid represents an entity that can be thought of as either a generator or a load. Planned islanding has recently been considered for improved reliability and blackout prevention [2], [3].

Intentional islanding may be required under various circumstances: as a means of shedding load; to modify system characteristics (voltage profile or line flows); or as a means to improve the reliability of the local grid by isolating it from the system during disturbances. Islanding of certain distribution feeders (medium voltage distribution lines at 25 kV and 12.5 kV) may also have other benefits that have yet to be understood, particularly during disturbances.

An Ontario Ministry of Energy Report resulting from the August 14, 2003 blackout describes how two unintentional islands were formed in parts of Ontario and Northern United States and actually helped in returning the system to normal operating condition. These areas were able to remain in operation during the blackout and were largely unaffected. Furthermore, these areas helped in the eventual start-up of the system as it was used as a base system for those generators without blackstart capability, [5].

The MicroGrid must not only be able to operate in islanded mode and meet the load requirements, but it must also be able to smoothly transfer between the two modes of operation, namely islanded and grid connected mode, for which limited technical studies have been published [6]. This requires not only additional equipment but also the adoption or the development of various control, protection, and system management principles that are quite different from the way in which the conventional power system is operated [7].

This paper presents a case study of a 25 kV distribution feeder in British Columbia, Canada, that is operated by BC Hydro and has been equipped for planned islanding. An independent power producer (IPP) is connected to the distribution feeder and has equipment and controls to operate in both islanded and grid connected modes. The characteristics of this system, which has functioned successfully during the past 10 years, are outlined and serve as a model for future cases.

II. BC Hydro Background

The BC Hydro system has a peak load of 9,400 MW, 1.6 million customers and serves 97% of the population of the Province of British Columbia (BC) on the west coast of Canada. The BC Hydro system is predominantly dependent on hydro-electric generation. The main load centres are on the coast in the greater Vancouver area, on Vancouver Island in Victoria and in the interior of the province in some of the smaller cities, interconnected by 75,000 km of transmission and distribution lines. BC Hydro transmission voltages are 69 kV to 500 kV, and primary distribution voltages are 25 kV and 12.5 kV. Many of the rural towns are

fed by long transmission or distribution lines which often pass through fairly rough terrain.

Historically, BC Hydro has experienced problems with various radial transmission lines as a result of “low-probability high-impact” events, which have resulted in prolonged outages in some communities. In one case in August 2003, 10 km of wood pole radial 138 kV transmission line burnt down during a “wild” forest fire, resulting in a blackout to seven communities. A number of 1.85 MW rented diesel generators were brought in from Alberta province while the transmission line was repaired over a 5-week period. The loads were without power for 2-3 days at the beginning of the transmission line outage. Further, three existing feeder-connected hydro IPPs, rated from 1.5 MW to 6 MW and located in the affected communities, could not operate in island mode because they were not built with islanding capability.

Consequently, BC Hydro has been re-evaluating its system planning in many of these areas. Additional transmission lines have not always been a feasible solution due to high capital cost and right-of-way acquisition issues. Furthermore, the added lines may be subjected to the same low-probability event so may contribute little to added system reliability. Planned islanding has been considered as a reliable alternative and planned islanding of a BC Hydro 25 kV Boston Bar distribution feeder has been performed successfully numerous times during the past decade.

III. Boston Bar Case Study

The BC Hydro Boston Bar 69/25 kV substation is supplied from 60 km of radial 69 kV transmission line from the south in the town of Hope. The majority of the line is built off the highway and passes through steep canyon, which is subject to rock, mud, and snow slides and where access is difficult. On average, the line experiences 12-20 hour outages a couple of times per year. The substation has one 14 MVA transformer which serves three 25 kV feeders. An independent power producer (IPP) operates an 8.6 MVA run-of-river hydro-electric plant which is connected to one of the feeders about 8.3 km south of Boston Bar on the west side of the Fraser River, Fig. 1. The generating station is equipped with islanding

capability and islands the interconnected 25 kV feeder typically twice per year for about 15 hours per occasion.

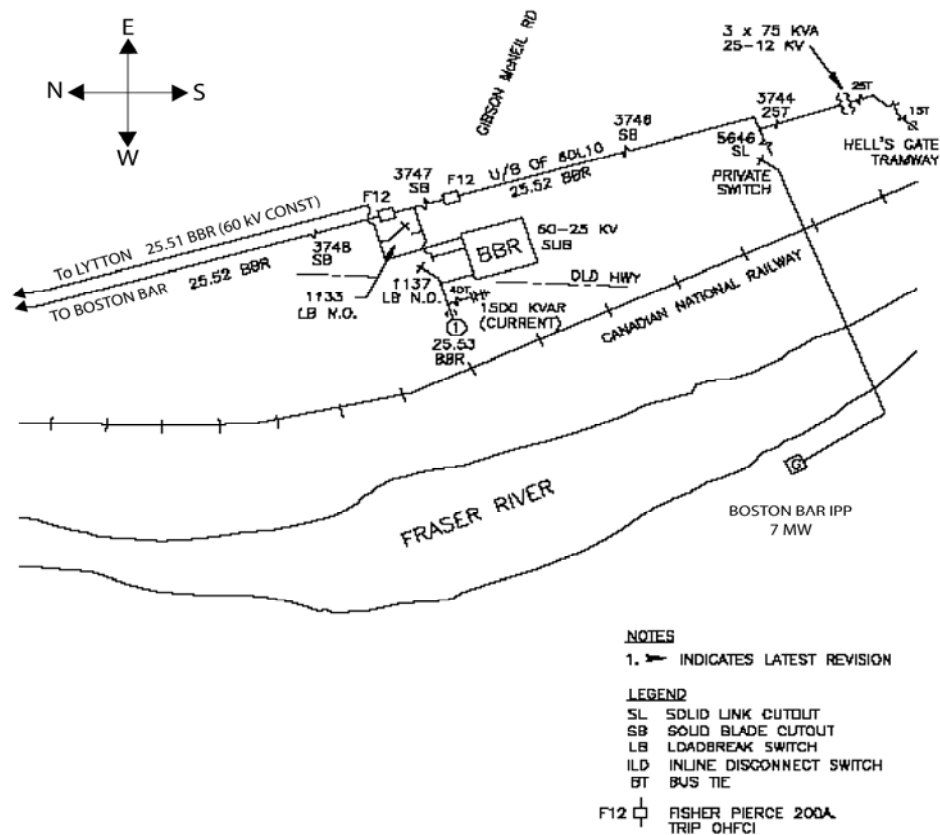


Fig. 1 Boston Bar system with interconnected IPP

A. System Representation

The 8.6 MVA Boston Bar IPP hydro plant, in service in April 1995, consists of two 3.5 MW, pf 0.80, generators at 4.16 kV, which are connected to the 25 kV feeder which has a winter peak load of 3 MVA. The 8.75 MVA IPP entrance transformer is HV grounded wye and LV delta and is energized from the generators and not from the BC Hydro grid, so that the transformer excitation voltage flicker is not imposed on BC Hydro load customers. The penstock is fed by Scuzzy Creek, whose water supply dictates the output of the plant. Typically the plant can generate as much as 8 MW during the spring and summer compared with an average of 3 MW during the winter months. A remote operator located in the town of Boston Bar monitors the plant.

The generating station is equipped with various protection relays including over/under voltage and frequency. Table 1 summarizes the quality protection settings while Fig. 2 presents the single line diagram of the interconnection with the various equipment labelled. Various additional equipment, protection, and controls are also required in order to transfer to islanding mode, which is discussed in the following section.

Table 1: Over/under frequency and voltage settings for Boston Bar IPP

Under/Over Frequency 81 O/U			
	Nominal	Instantaneous trip	Delay trip
Grid-connected	60 Hz	>60.5, <59.5	Not applicable
Dead Load Pickup	60 Hz	<55, >65	Not applicable
Islanded Steady-State	60 Hz	<53, >67	<59.5 >60.5, 20 sec
Under/Over Voltage 27/59			
	Continuous range	Delay (1 sec)	
V_{in} (any phase)	$0.9 < V < 1.1$	<0.9, >1.1	

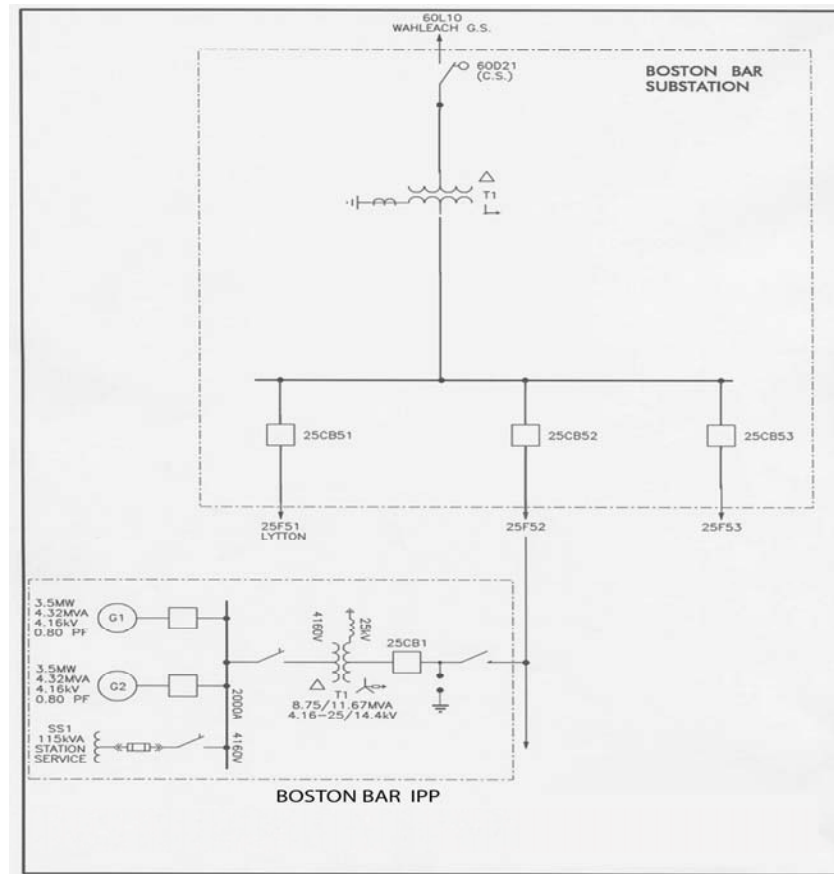


Fig. 2: System diagram of interconnection of IPP to BC Hydro system

B. *Planned Islanding*

The Boston Bar IPP differs from most distributed generators (DG) in that it may remain connected following loss of the grid, thus sustaining the 25 kV feeder island. Therefore, additional equipment exists which is not in place for most DG interconnections. Depending on the creek water level, the IPP may be able to pick up all or only a portion of the feeder load. As well, there are various procedures that must be adhered to when starting up the generators, synchronizing to the grid, and disconnection of the IPP.

The IPP paid the incremental capital cost associated with islanding capability, including the following:

- i. Automatic voltage regulators (AVR)/exciters have positive field forcing for current boost during feeder faults in order to assist overcurrent protection,
- ii. Black start capability via 55 kW diesel,
- iii. Engineered mass for turbines & generators. This is the inertia constant H in MW-sec/MVA,
- iv. BC Hydro approval of exciters, AVR & turbine speed control governors,
- v. Grid & off-grid settings for 25 kV line power quality and overcurrent protection,
- vi. Synchronizing capability at BC Hydro substation 25 kV feeder breaker 25CB52, so BC Hydro can synchronize to the running IPP when BC Hydro recovers from a substation or transmission line outage,
- vii. Real-time IPP data telemetry via telephone lease copper wire from the IPP to Boston Bar substation then via BC Hydro SCADA to the BC Hydro Area Control Centre,
- viii. Commissioning tests for island operation.

The IPP is paid a bonus when it is able to sustain the island as compensation for its incremental capital cost for islanding capability. The incremental capital cost was about \$500,000 CDN on a capital cost base of \$12 million CDN.

The islanding scenario is as follows. In the event of a permanent fault in the BC Hydro Boston Bar substation or its 69 kV transmission supply, protection tripping

is extended to the substation 25 kV feeder CB 25CB52. Opening of this substation feeder CB is telemetered to the IPP and the IPP automatically changes to the line protection settings for island mode. The IPP will hold the feeder island unless quality protection relays (under/over voltage or under/over frequency) pick up and clear the IPP from the 25 kV feeder. If the IPP disconnects from the 25 kV feeder, it will re-start then energize the dead feeder following a telephone call request from the BC Hydro Area Control Centre. Further, BC Hydro may sectionalize the feeder if water level at Scuzzy Creek is low. In rare cases the IPP may also island feeder 25F51 and/or feeder 25F53 through the BC Hydro substation LV 25 kV bus and feeder circuit breakers if the IPP has sufficient water available.

In the event of a 25 kV feeder line fault, both the Boston Bar substation feeder CB 25CB52 and the IPP 25 kV entrance CB should detect and trip. Remote close of feeder breaker 25CB52 from the Area Control Centre is voltage-supervised via three VT's on the load (IPP) side of the breaker. Auto-reclose of 25CB52 is not in service.

C. *IPP Commissioning*

In order to be accepted for islanding capability, the IPP underwent commissioning tests to demonstrate that it is capable of operating in the two required modes of operation, as well as transfer between these modes of operation. This consists of parallel operation tests: synchronization (both manual and automatic), output load, voltage and frequency control, and load rejection. Island operation tests include: dead-load pick-up, load following capability, voltage and frequency control and transfer to island operation (one unit at a time then both in parallel).

IV. Summary

The planned islanding of a BC Hydro Boston Bar 25 kV feeder has demonstrated excellent reliability since 1995 and serves as a model case study. The IPP has improved BC Hydro system reliability in this area while financial gains were realised for the IPP. However, various issues need further consideration, namely the ideal protection settings, commissioning tests,

equipment specifications, and how to compensate the IPP for the incremental capital cost associated with islanding capability. Both the cost of the additional equipment that is required as well as the added reliability must be taken into consideration when assessing the value of planned islanding. The criteria for identification of other potential feeders for planned islanding operation is another important issue and this alternative will become more important as additional IPPs connect to the BC Hydro distribution system.

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