DISTRIBUTION POWER GENERATOR ISLANDING GUIDELINES

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1.0 INTRODUCTION

1.1 Purpose

The purpose of this report is to outline how BC Hydro will consider the technical attributes of power generator (PG) planned islanding in the integrated distribution system at 35 kV and below. The commercial terms for PG planned islanding are excluded and will be developed separately.

This report focuses on new PG interconnections, but could be applied to the retrofit of an existing PG for planned islanding capability.

The current electric utility practice for PGs on the interconnected distribution system is to de-energize the PG generators when the utility transmission or distribution circuit is out of service. This is to ensure customers' power quality, field crew safety and to avoid operation and protection complexities.

1.2 PG Islanding

BC Hydro has an objective to improve distribution customer service reliability in locations where the reliability is below customer expectations. Customer service reliability may improve if a PG can island with part or all BC Hydro customer loads on the interconnected feeder and/or other feeders from the same distribution substation. Reliability improvements are more likely when the transmission supply to the substation is not secure (single radial supply) and/or the PG interconnecting feeder is long and subjected to trees, storms, motor vehicle accidents, etc. The BC Hydro distribution feeders of interest operate at 12.5 kV and 25 kV.

Benefits may accrue to a PG built for planned islanding, such as selling electricity to BC Hydro during certain outages.

> Islanding is defined for this report as the condition when a portion of the BC Hydro system is energized by one or more PG facilities and that portion of the system is separated electrically from the rest of the BC Hydro system. PG islanding may be inadvertent or intentional.
>
> Planned islanding capability is the ability of a PG to continue to supply or electrically energize in a safe, controlled and reliable manner, part of the distribution system, including customer loads, that is separated from the rest of transmission or distribution system.

The discussion below is limited to an island consisting of either a whole or partial distribution feeder. The island does not include any part of the distribution substation or the transmission system. However, the BC Transmission Corporation (BCTC) would consider islanding of a distribution substation low voltage bus for a specific PG project, if requested by BC Hydro.

1.3 Current Islanding Practice

Nearly all the BC Hydro distribution feeders are radial, resulting in a power outage for all the load customers connected to the feeder during a feeder outage. A PG without planned islanding capability does not provide increased customer service reliability since the PG must be de-energized during the outage.

The PG interconnection may reduce the reliability of the feeder. For example, auto-reclose of the substation feeder CB and main line recloser may be disabled, and one or more of the existing protection devices in the feeder may be removed to support protection co-ordination between the PG entrance protection and the BC Hydro upstream protection device. Feeder outage restoration time may increase when line crews travel to PG sites to lock open and tag the PG entrance switch or service cut-outs under BC Hydro Safety Practice Regulations.

Customer reliability is an important consideration for customers and BC Hydro. During a power outage, the utility loses customer satisfaction while customers lose business and/or convenience. Different customers have different concerns and different costs due to the outage. The reduction of power outage frequency and outage duration is desirable for society as a whole. If, during a power outage, the PG with planned islanding capability is allowed to form an island with some or all of the customer loads on the BC Hydro feeder and continue to supply the loads, the reliability to those loads could improve.

1.4 PG Islanding Issues

To enable PGs to operate in a load island, numerous issues need to be considered and resolved. These include:

- Islanding scenario: inadvertent islanding or planned islanding,
- System reliability: reliability improved or decreased or remains the same,
- Power quality: potential power quality problems,
- Additional BC Hydro/PG equipment and associated costs for planned islanding,
- Additional operation and safety requirements at BC Hydro Control Centre, safety concerns during restoration and possibly grounding and/or protection issues,
- Economic and commercial considerations.

2.0 RELIABILITY

2.1 Introduction

This section defines the most used distribution reliability indices, and relate these to BC Hydro practice with Customer Based Reliability (CBR).

2.2 Reliability Indices

Reliability statistics, based on long-duration interruptions, are the “yardstick” used by most power utilities and regulators to quantify the security of power supply in accordance with national standards. Faults on the distribution system cause most long-duration interruptions, and a fuse, breaker, recloser or sectionalizer locks-out the faulted section.

Most electrical utilities use reliability indices to quantify and record the performance of the utility region or circuit.

Utilities most commonly use two indices, SAIFI and SAIDI, to benchmark reliability. These characterize the frequency and duration of interruptions as follows:

SAIFI, System average interruption frequency index

$$\text{SAIFI} = \frac{\text{Total number of customer interruptions (per year)}}{\text{Total number of customers served}}$$

Typically, a utility’s customers average between one and two sustained interruptions per year.

SAIDI, System average interruptions duration index

$$\text{SAIDI} = \frac{\text{Sum of all customer interruption durations (hours or min. / year)}}{\text{Total number of customers served}}$$

SAIDI measures the total duration of interruptions; SAIDI is cited in units of hours or minutes per year. Other common names for SAIDI are CMI and CMO abbreviations for customer minutes of interruption or outage.

Another related index is CAIDI, the customer average interruption duration frequency index.

$$\text{CAIDI} = \frac{\text{SAIDI}}{\text{SAIFI}} = \frac{\text{Sum of all customer interruption durations}}{\text{Total number of customer interruptions}}$$

A comparison of reliability indices between BC Hydro and the Canadian Electricity Association (CEA) follows:

	SAIFI			SAIDI	
YEAR	BCH	CEA		BCH	CEA
F2000	1.21	2.59		2.28	4.31
F2001	1.18	2.26		2.51	3.23
F2002	1.41	2.41		3.60	3.67
F2003	1.45	2.33		3.77	4.06
F2004	1.63	2.67		4.51	10.65
F2005	1.47	1.98		3.96	3.95

Source:

1. BC Hydro Distribution Service Performance Report F2000/01 to F2004/05,
2. CEA Annual Service Continuity Report on Distribution System Performance in Electrical Utilities 2000 to 2004.

The BC Hydro data for a given fiscal year is compared to CEA's data for the prior calendar year, e.g. BC Hydro data for F2005 is compared to CEA's data for calendar year 2004. Both BCH and CEA data includes all events.

2.3 Customer Based Reliability

BC Hydro Customer Based Reliability (CBR) is a transparent mechanism that will imbed the reliability needs and expectations of BC Hydro's customers in BC Hydro asset management decisions. In the past, system upgrades were targeted to areas with the highest customer density, with no regard to the different needs of customers. This "system" focus was practical because it delivered the greatest improvement in the metrics used to monitor system performance. This approach did not incorporate the fact that many customers were satisfied with the value they received for existing performance. The continued development of CBR will focus on customer needs and initiate improvement where the power system reliability does not meet their requirements.

PGs with planned islanding capability, connected to the distribution system, may be a solution at locations that require reliability improvement. However, the technical and economic attributes of PG planned islanding at a given location will be compared with other options, such as reinforcing the BC Hydro wires delivery system.

3.0 GUIDELINES FOR EVALUATING PG ISLANDING

3.1 Introduction

This section outlines the technical and economic attributes of PG planned islanding in the integrated distribution system at 35 kV and below. The focus is on future PG interconnections, but could be applied to the retrofit of an existing PG for planned islanding capability. The following are guidelines used by BC Hydro to evaluate the feasibility.

3.2 Initial Considerations

A PG may be a candidate for a planned islanding study where BC Hydro service reliability falls outside customer expectations under BC Hydro Customer Based Reliability and the PG generator is a synchronous generator and willing to consider islanding.

3.3 Additional Considerations

If the requirements in 3.2 Initial Considerations above are met, the following guidelines are considered:

3.3.1 PG Continuous Capacity

Is the proposed PG generation output cyclic in nature due to water flow or another reason? Prepare a 12-month profile of the feeder load and the proposed PG output over the annual period. The PG output must be equal to or greater than the feeder load for each hour of the year. Alternatively, feeder sectionalizing via manual means or remote control line devices (reclosers or line switches) may be considered. Only the benefits to affected customers applies if feeder sectionalizing is required.

3.3.2 Utility Feeder Reliability Improvements

Can BC Hydro adequately improve its infrastructure reliability at a lower life-cycle cost than PG planned islanding? If so, PG planned islanding is not considered.

3.3.3 PG Considerations for Planned Islanding

The following technical items will need to be considered case-by-case along with the other requirements discussed in earlier Sections before entering into a discussion for providing planned islanding with the PG:

- Generators capable of maintaining the load on tripping of the substation feeder CB (other than for feeder fault),
- Generators with broader VAR control for loads to a power factor of +/- 0.8, plus load following capability,
- Fast acting prime mover speed governor and exciters,
- Inertia and control system to pick up and hold dead feeder load,
- Black start capability,
- Capability to maintain the power quality guidelines for the islanded feeder. Are there major machines or similar loads with large inrush or cyclic load (log chippers) in the feeder that makes PG islanding impracticable?,
- Operating data, generator ON/OFF status, primary breaker open/close status and operator communication to the BC Hydro Area Control Centre via real-time, always-on communication media.

3.3.4 BC Hydro Considerations for Planned Islanding

What modifications to the existing distribution system will be required for planned PG islanding of feeder load and at what cost? The following will need to be evaluated and priced:

- If the feeder's future MVA demand forecast is greater than PG islanded rating, a plan and cost for feeder sectionalization of the excess load,
- Line voltage regulators: controls modifications/upgrading,
- Line reclosers: auto on and off, overcurrent bi-directionality, voltage-supervised closing,
- Line fuses in grid-connect mode and island mode,
- BC Hydro synchronizing to PG at substation feeder CB,
- Additional work to incorporate PG real-time operating data in the Area Control Centre and inter-operator communications,
- BC Hydro staff time to review PG design and equipment specifications, additional Control Centre Operator and Local Operating Order procedures, and PG commissioning tests for grid-connected mode, response to an island on separation and feeder dead load pickup,

Implementation of PG planned islanding would require the agreement of BC Hydro and the PG owner, plus addendums to the Electricity Purchase Agreement (EPA), Project Interconnection Requirements and the Interconnection Agreement. If the PG has an existing EPA with BC Hydro, discussions with the PG must ensure that the islanding provisions do not conflict with any requirements in the EPA. If they do, Power Acquisitions and Contract Management will be involved in the negotiations.

APPENDIX

A TECHNICAL CONSIDERATIONS for PG ISLANDING

A.1 General

This section outlines the BC Hydro technical criteria for power generators connecting to the distribution system, and discusses technical considerations for PG planned islanding.

BC Hydro produced the document *"BC Hydro 35 kV and Below Interconnection Requirements for Power Generators"*, June 2004, for rotating-machine generators connecting to the distribution system. This document states the minimum technical requirements the Power Generator must meet and identifies expected system conditions the PG facilities could encounter while connected to the BCH system.

BC Hydro writes Project Interconnection Requirements (PIR) for each PG as part of the Interconnection Agreement, to cover the project's specific technical interconnection requirements, distribution primary service and protection, control and communications facilities.

A.2 Distribution Equipment Rating

The BC Hydro distribution wires system comprises overhead and underground equipment at 35 kV and below, from the BC Hydro substation fence to the customer load or power generator. 35 kV distribution exists at some Interior locations by stepping up in the field from a 14.4 / 25 kV primary line to 19.9/35 kV.

BC Hydro current practice does not permit conductors larger than trunk-line standard of 336 kcmil ASC conductor, and with the capacity limitations of feeder reactors and feeder cables, the size of a PG on a 25 kV distribution feeder is limited to a rating of about 17 MVA.

The PG contribution to feeder fault currents requires a review of the protection equipment (fuses, reclosers, sectionalizers, faulted circuit indicators) in the BC Hydro feeder. BC Hydro may also replace three single-phase hydraulically controlled line reclosers with three-phase electronically controlled reclosers because the existing recloser trip coil rating may be too low. Or, BC Hydro may use three-phase reclosers where line fuses will not coordinate with the substation feeder CB protection.

The thermal ampacity of the feeder primary conductor or cable is checked for load flow. Additionally, voltage regulation between the PG and the BC Hydro feeder circuit breaker is checked. For PG connections to rural lines, feeder voltage regulation is typically the limiting factor before wire gauge ampacity is exceeded.

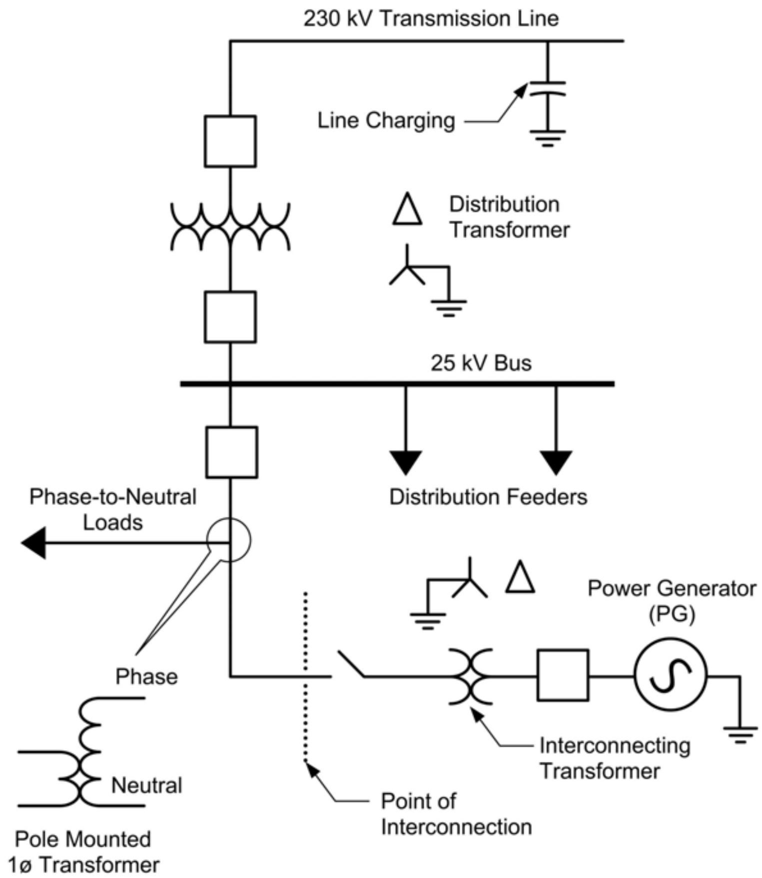
Feeder line voltage regulators subjected to reverse power flow are retrofitted for reverse power sensing and reverse power tap-changing. Alternatively, BC Hydro replaces the voltage regulators with units designed for bi-directional power sensing and reverse power tap-changing. Bi-directional regulators have two control panels - one for the forward direction and one for the reverse direction. Also, line voltage regulators at a specific location may need to be replaced with higher ampacity units.

A.3 PG System Grounding

BC Hydro distribution feeders are four-wire, three-phase with multi-grounded common neutral conductor. Figure 1 shows a simplified one-line diagram of a distribution station, which is connected to transmission system via 230 / 25 kV delta-wye substation transformer. 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 PG connected to a feeder via an interconnecting transformer. Consistent with a generator-unit transformer configuration, the low-voltage (or PG) side of the interconnecting transformer is delta, and the high-voltage or 25 kV side is connected grounded-wye. A solidly grounded PG interconnecting transformer can reduce the sensitivity of the BC Hydro feeder ground protection to an unacceptable level. BC Hydro typically specifies that PG entrance transformers be reactance grounded on the BC Hydro side.

A PG connected to the utility system via an ungrounded interconnecting transformer can expose the utility and its customers to unacceptable high voltages during ground faults.

Figure 1 A Typical Distribution System with PG on a Feeder



A.4 PG Capacity and Island Load

BC Hydro has developed a “Two-to-One” rule-of-thumb to estimate if a PG can inadvertently island the BC Hydro feeder, part or all of the distribution substation or the transmission line that supplies the substation. The “Two-to-One” rule is based on the assumption that an island is not sustainable where the annual minimum load in the island is at least twice the island’s generation. In other words, in the event that a PG with generation capacity *x* MVA and BC Hydro customer loads of 2*x* MVA form an island, then the PG’s protection and control will shut down the PG. The “Two-to-One” rule-of-thumb aids in determining if PG interconnection technical studies will be done for a given BC Hydro system “element”, i.e. feeder, substation bus, entire substation, or transmission line. Some utilities use a more conservative “Three-to-One” rule of-thumb.

A.5 PG Load Pickup

On opening of the utility substation feeder breaker, a directly connected signal to the PG prime mover controller may be required to initiate a switch to load-following mode to maintain voltage and power flow into the island. The PG overcurrent protection relays need to be capable of dual settings, one for on-grid and one for off-grid, in some cases initiated by the above substation feeder breaker.

There will be occurrences where the PG will not successfully maintain the island on opening of the BC Hydro substation feeder breaker due to the nature of the disturbance that initiated the trip and the voltage and frequency excursions that may be present immediately after being islanded. The PG must have:

- A direct means of voice communication between the BC Hydro Control Centre and the PG operator,
- Black start power capability to re-start while the utility source is unavailable,
- Appropriate controls, governor, exciter, inertia, etc to pick up and hold dead feeder load.

If islanded operation is considered for PG’s that do not have the capability to supply the total feeder load during islanded operation, feeder load shedding or feeder sectionalizing is required. System load shedding is usually done by automatic or supervisory control following selected breaker trips. High speed load shedding would be difficult to accomplish on a distribution feeder, where customers are typically connected through fused switches or similar disconnecting devices that do not have supervisory control. For an extended islanded operation, manual switching to disconnect customers and/or telephone requests to high-load customers to disconnect could be required but it would mean temporary tripping the PG for some period of time. Alternatively, a feeder could be sectionalized via remotely controlled line reclosers or line switches.

A.6 PG With Support For Islanding

Where the distribution feeder requires reliability improvement and a PG is too small to operate as a stand-alone island, consideration could be given to prepare the PG to support an island carried by another local PG or mobile temporary diesel generation. This would affect, for the supporting PG, the selection of relaying for multiple settings for line overcurrent protection, possibly multiple relay settings for power quality protection and possibly additional governor control settings.

A.7 BC Hydro System Equipment

In this section we consider requirements in the case of only feeder islands. Substation bus islands and transmission islands are outside the scope of this discussion.

BC Hydro assumes the feeder annual minimum load is 25% of the annual feeder peak load, in the absence of feeder measured load data. The feeder island is assumed to be non-sustainable when the annual minimum load on PG feeder is at least twice the maximum PG generating capacity. Should protection initiated trips separate the PG from the utility system, the PG will shut-down or become un-excited on its own due to fast declining frequency (and voltage) even when its own protection is unable to detect the fault that initiated substation feeder breaker tripping. After separation, the lost load on PG feeder can be restored via BC Hydro automatic reclosing or supervisory close without any concerns of the PG being on-line. Thus, a PG can interconnect with minimal BC Hydro P&C requirements if it's size is small enough that it cannot form a sustainable feeder island using the “Two-to-One” rule-of-thumb.

If a PG is capable of forming a sustainable planned feeder island, (as per “Two-to-One” rule when the island minimum load is less than twice the PG rating), distribution substation equipment is:

- Substation Feeder Circuit Breaker: suitably rated and capable of interrupting with sources on both sides of poles. Substation feeder circuit reclosers, where they exist, are not acceptable because their built-in protection features are not suitable for PG interconnection. Further they may not be capable of interrupting with sources on both sides of poles, and their trip coil rating may be too low,
- Substation Feeder VTs (voltage transformer): three one-phase VTs on the load side of the substation feeder breaker to allow voltage-supervised local or remote closing of the substation feeder CB on restoration, to prevent out-of-synchronism closing on the PG,
- Substation Feeder Digital Protection Relays: equipped with features such as voltage supervision, sync-check, directional overcurrent element, out-of-step detection and disturbance monitoring.

Substation feeder CB load-side VT and deadline logic are not required when:

- PG is connected to an express feeder with no BC Hydro loads (with no auto-reclosing) or
- PG is connected to an underground cable feeder, i.e. Control Centre operator will not close the feeder breaker before cable inspection after tripping.

There may be situations when load on the PG feeder is served by the spare feeder position (commonly referred to as a tie-bus in BC Hydro) to allow maintenance of the PG feeder breaker. In this case, the load side VT would be energized and prevent restoration of PG feeder breaker because of deadline logic. Rather than interrupting load, sync-check with live-bus-live-line logic can be used to restore the PG feeder breaker. Note that the PG is off-line when its interconnecting feeder is supplied from the substation bus-tie feeder position.

In rare cases when PG in-feed is strong and the utility system is weak, protection on the PG feeder may mis-coordinate for a fault on the adjacent feeder. Reverse fault current in the PG feeder may be nearly the same, resulting in simultaneous trips of both feeders. The solution may require protection re-coordinating or directionalizing the protection on the PG feeder. A similar problem can be encountered in fuse saving schemes, where the PG feeder has a low-set ground instantaneous element. This low-set instantaneous ground protection may trip on reverse faults. In this case, either the fuse savings scheme can not be applied or the ground instantaneous protection may require directionalization or de-sensitization.

A.8 Out-Of Step Detection and Tripping Duty

A PG and a utility operating in parallel may go out-of-step and swing against each other under certain contingencies. The engineering cost of full dynamic simulations to identify out-of-step conditions and location of swing electrical centre is justified for some PG interconnections, e.g. BC Hydro source is weak and PG MVA rating is large compared to substation load. Alternatively, a simple analytical method is used. The positive sequence impedances of the utility source at low voltage bus (Xs), distribution feeder (Xf), interconnecting transformer (Xt) and PG generator (X’d) are plotted on an R-X diagram. Use of positive sequence Thevènin impedance of utility for the weakest utility source condition (or highest source impedance) is recommended, as it will indicate if there is any possibility of swing impedance locus traversing the feeder or utility system. The location of the swing centre is midway on the impedance line between the utility and PG sources, or can be estimated from the R-X diagram by assuming that utility and PG voltages behind the source impedances are equal and opposite. In most cases, the sum of the PG and interconnecting transformer impedances is much larger than the sum of the feeder and utility source impedances. The swing centre typically lies on the negative X-axis. Therefore, out-of step protection in general, if required, is part of PG generator or interconnecting transformer protection, rather than a utility interconnection protection requirement. However, if the swing centre is within the utility system or on the feeder, a multi-function relay for the feeder protection may be required.

Proximity of the swing centre to the utility source and its detection by the feeder protection requires tripping of the feeder breaker to separate utility system and the PG. As the utility distribution system is designed for radial source, the feeder breaker may not be rated for out-of-step trip duty. When out-of-step tripping is initiated, the two voltage sources (utility and PG) across the feeder breaker are expected to be close to 180^{o} out-of-phase and would impose twice the transient recovery voltage (TRV) compared to a single source (no PG).

A breaker not rated for out-of-step trip duty may re-strike (or re-ignite) and fail. Where possible, BC Hydro accepts out-of-step tripping delayed beyond first pole slip or trip-on-the-way-out, to ensure that the two voltage sources are not in anti-phase when breaker poles begin to part. Delayed tripping reduces TRV stress on the breaker, and thereby avoids its replacement. However, delayed tripping requires the PG to be capable of withstanding at least one pole slip without damage to its generator rotor shaft.

A.9 Transmission Line Transient Overvoltages and Transfer Trip

When a PG is connected via a feeder supplied from a distribution substation transformer that is high-side ungrounded (the BC Hydro standard), a line-to-ground fault on the transmission line and the trip of the utility remote transmission breaker can raise voltages on the healthy phases of the transmission line serving the distribution substation. These over-voltages can be much higher than line-to-line level when the PG becomes the only source backfeeding into a line-to-ground fault on an ungrounded transmission system.

Referring to Figure 1, a line to ground fault on the transmission system will trip the utility remote transmission line breaker first as there is no zero sequence current from the PG to fault, due to the delta-connected high-side of distribution station transformer. In the time duration after tripping of the remote utility terminal (which provides effective grounding to the line) and before isolation of the PG, the PG is the only source connected to line-to-ground fault on an ungrounded transmission system. Over-voltages on the healthy phases for this duration can rise much above line-to-line voltage if the inductive reactance of the system under weak source condition exhibits low frequency series resonance with zero sequence line capacitance of the transmission line. The system inductive reactance is the sum of the positive and negative sequence reactances of PG generator, PG transformer, distribution feeder, utility distribution substation transformer, and transmission line. Under a weak source (high source impedance) and a long line (about 100 km) and high voltage (230 kV) transmission line (high charging capacitance), a possibility of near 60-Hz series resonance is strong.

Transfer trip from a remote transmission CB to the substation feeder CB where PG is connected is required to avoid unacceptable temporary overvoltage during the clearing of line-to-ground transmission faults.

A.10 PG Control and Visibility

PG ratings from 1 to 10 MVA are required to provide operating data and interconnection status to the BC Hydro Area Control Centre. Required data are plant MW, MVAr, MWh & kV and interconnection status open/closed via unsolicited (PG initiated) report-by-exception or by polling by BC Hydro. This can be done using dial-up Intelligent Electronic Device (IED) with DNP 3.0 protocol with a 2-minute maximum to establish connection for BC Hydro interrogation on demand via a telephone analogue business line with no other telecom uses for this line in the PG plant.

For PG ratings over 10 MVA, the PG operating data required is unit MW, MVAr, MWh & kV, plus unit connection status & unit running status. This is a real-time report by exception using an IED with DNP 3.0 protocol and an always-on communication link, i.e. telephone lease, power line carrier, fibre optic, or microwave.

B. OPERATIONS AND SAFETY

B.1 Introduction

In addition to the requirements for the physical interconnection of a PG to the utility grid and its protection, there are operation and safety considerations in the PIR with each PG. These operation and safety considerations are discussed in this section along with suggested additions for those interconnections with planned islanding.

B.2 Operations

In normal non-islanded operation, the utility grid system stiffness generally ensures that frequency and voltage to customers is controlled and maintained within power quality guidelines. The stability provided by the system is lost when the feeder becomes an island supplied only by the PG who, nevertheless, is required to continue maintaining the steady state voltage and frequency limits defined by the PIR.

For a planned islanding interconnection, there are additional operating interface features that are necessary to ensure appropriate operation and customer power quality. To ensure quick operations reaction, the status and data link needs to be real-time continuous over a dedicated telephone lease line or equal and unit Hz and A are also required in addition to unit MW, MVAr, kV, MW.h, and interconnection CB open/close status.

For an unforeseen event where power quality deteriorates continuously outside acceptable limits, a direct means for the Area Control Centre Person-in-Charge to trip the PG's interconnection CB should be considered to avoid or minimise damage to BC Hydro customers within the feeder island.

In order to avoid an unnecessary customer outage when the BC Hydro substation recovers and is ready to be connected to the feeder, auto-sychronization initiated by the BC Hydro Control Centre to the PG island via the substation feeder breaker may be warranted.

B.3 Safety

A PG with islanding capability may need to automatically change protection settings to alternate settings to try and hold the island formed on opening of the substation CB, and when unable to do so, to re-start its generators and pick up the dead load. The BC Hydro Local Operating Order (LOO) defines how the Control Centre closes the feeder CB when power is restored to the substation. A sync-check relay must determine when the feeder CB can close for the PG powered island condition. Load-side VTs for voltage verification permit the CB to be closed when the island is not powered. Direct voice communication between the operators would be beneficial.

The BC Hydro dispatchers and line-workers for the feeder require additional training regarding the operation of the PG during a substation outage. When non-live work is done on the feeder, the substation and the PG need to be isolated from the feeder. The conductors between the substation and the PG will become Power System Safety protection (PSSP) Level VI equipment and must be under Control Centre direct control, meaning that Self Protection Rules cannot be used. Operating drawings and Control Centre mimics need to indicate when the feeder is operating as an island. The Local Operating Order needs to cover islanded operations as a separate category.