

Dispersed Generation Interconnection—Utility Perspective

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Abstract—Interconnection of generation to an electric distribution system, which is primarily designed to serve radial loads, must not compromise reliability and quality of supply to customers or safety of public and equipment. This paper presents criteria used by BC Hydro, the third largest utility in Canada, to determine the requirements for interconnecting a generating source to its distribution system. The presented criteria discuss tradeoff involved in specifying the grounding connection of interconnecting transformer or how the size of a distributed generator impacts protection upgrades within the utility system, out-of-step tripping duty on the feeder breaker, and requirement of transfer trip to avoid temporary overvoltages. These criteria are applied consistently and uniformly to minimize cost of interconnection engineering. They are based on sound engineering principles to ensure that interconnection upgrades specified are justifiable and defensible, if necessary, to the utility's regulator to ensure open access of the grid.

Index Terms—Distributed generation, distributed resource interconnection, independent power producer (IPP), interconnection protection, series resonance, transfer trip, transformer grounding.

I. INTRODUCTION

OPEN ACCESS to utility wires, the desire for green or less-polluting electric generation to meet environmental targets, and technological advancements in alternative energy sources are some of the reasons for increased growth of distributed or dispersed-resource (DR) generation, i.e., small-scale generators connecting at the distribution level. However, introducing a generator within the distribution system, which is designed and built to serve loads on radial lines, presents the unwanted redistribution of fault current and possibility of temporary overvoltages. Unless the DR-utility interface, including the grounding of interconnecting transformer, is properly designed, a source in the distribution system can threaten the public safety, customer installations, and jeopardize the reliable operation of the distribution system and the DR itself. Depending upon the size and location, DR generation can change the way the distribution system is protected and operated, both in normal operation and during faults.

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BC Hydro, the third largest utility in Canada, has an aggressive program to encourage DR generation. At present, BC Hydro has more than 50 generating stations connected to its distribution system. The smallest generating station is about 70 kW and the largest is about 34 MVA. Proposals for DR interconnections are regularly received. These proposals are accurately assessed for interconnection cost using consistent and standardized technical criteria, which minimize the cost of interconnection engineering. These technical criteria have been developed over the years applying good utility practices and sound-engineering principles to ensure that the interconnection upgrades specified are justified. All interconnection requirements specified must also be defensible, if necessary, to the utility's regulator to ensure an open access of the grid.

This paper outlines the technical criteria that are used by the BC Hydro to assess the requirements of small generators wanting to interconnect to the distribution system. Important considerations for distribution-system equipment ratings associated with generator interconnection are first presented. It follows with a discussion on the tradeoff between the temporary overvoltage and the protection sensitivity in specifying the grounding connection for interconnecting transformer. This paper then presents a “two-to-one” rule, and how this rule is applied in determining the system or protection upgrades within utility's system needed for DR interconnection. A distribution-substation feeder breaker with a generator connected on its feeder will have sources on both sides. With the sources on both sides, the breaker poles can be subjected to out-of-step tripping duty, in which the breaker may not be capable of withstanding. The paper discusses a simple method to identify if the swing center is close to the feeder breaker and a method to address the concern of out-of-step tripping duty. A weak source such as a DR, which ends up being the only generator back feeding into a ground fault on a long transmission line without effective grounding, can generate temporary overvoltages that are damaging to the electrical equipment. This paper provides an insight to the system phenomenon that leads to such temporary overvoltages and a mitigating technique using transfer trip. Before concluding, the paper briefly describes the remote control and visibility as well as revenue-metering requirements for DR interconnection.

With the exception of grounding requirements of interconnecting transformer, the paper does not discuss safety, equipment, and protection of DR itself. A separate BC Hydro document discusses these requirements [1]. Presented in this paper are the criteria specific to the BC Hydro system and which may differ from practices of other utilities. A new IEEE

standard 1547-2003 [2] also provides general technical specifications, performance, and test requirements of interconnecting distributed resources with the electric power system. Finally, all examples used in this paper ignore the resistive component of impedance for simplicity and ease of illustration.

II. DISTRIBUTION EQUIPMENT RATING

The distribution system is defined as the BC Hydro-owned overhead and underground equipment at 35 kV and below, from the BC Hydro substation fence out to the customer loads. A DR interconnection to the BC Hydro distribution system brings the following considerations for the distribution-system equipment ratings. The present BC Hydro practice does not allow wires bigger than trunk-line standard of 336 kCM ASC, which limits the upper level for aggregate DR on a distribution feeder to about 15 MVA.

A DR contribution to fault currents requires a review of the interrupting rating of area BC Hydro line fuses and line reclosers, and the interrupting rating of customer-owned service-entrance equipment (fuses or circuit breakers) at load customers served at 12.5- or 25-kV primary voltage. Also, BC Hydro may replace three single-phase hydraulically controlled line reclosers with three-phase electronically controlled reclosers. For example, the existing recloser trip coil rating may be too small or the BC Hydro may want to use three-phase reclosers so as not to impose single-pole line switching on the three-phase synchronous generators of DR and BC Hydro customer loads.

The thermal ampacity of the feeder primary conductor or cable is checked for load flow. Additionally, the voltage regulation between the DR and the BC Hydro-feeder circuit breaker is checked. The feeder voltage regulation is typically a limiting factor before the wire gauge ampacity becomes a limiting factor. The DR impact on the annual energy losses in the feeder is calculated and may affect the price the BC Hydro pays for the DR electricity.

Feeder line voltage regulators subjected to reverse power flow are retrofitted for reverse power sensing and reverse power tap changing, or, alternately, the BC Hydro replaces the voltage regulators with units designed for bidirectional power sensing and reverse power tap changing. Bidirectional 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 ampere rated units.

III. TRADEOFF IN INTERCONNECTING TRANSFORMER GROUNDING

BC Hydro distribution feeders are a four-wire, three phases, and one neutral system. Fig. 1 shows a simplified one-line diagram of a distribution station, which is connected to the transmission system via 230/25-kV delta-wye distribution 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 the phase and the neutral via pole-mounted transformers, which are rated for line-to-neutral voltage. Also, shown in

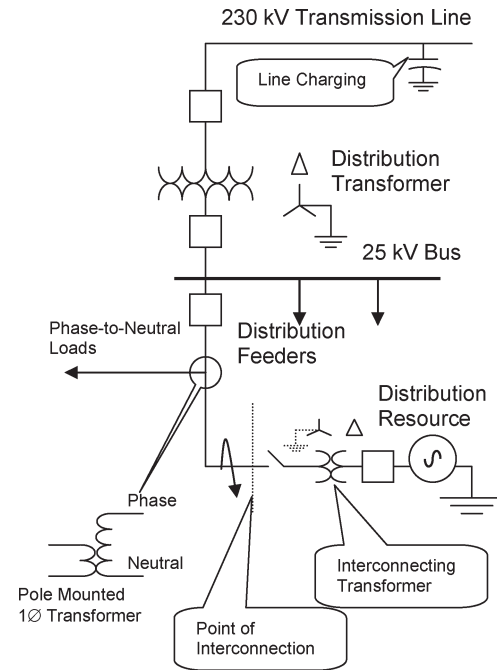


Fig. 1. Typical distribution system with DR on a feeder.

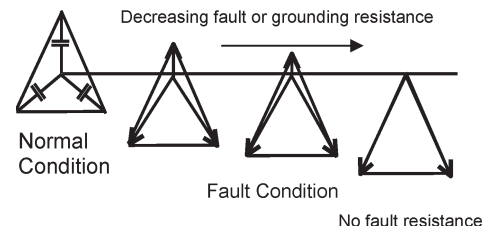


Fig. 2. Neutral shift at line-to-ground fault location in an ungrounded system.

the figure is a DR connected to a feeder via interconnecting transformer. Consistent with a generator-unit transformer configuration, the low-voltage (or DR) side of the interconnecting transformer is delta connected and the high-voltage or 25-kV side is wye connected. Grounding of high-voltage or wye-connected winding involves tradeoff between the safety of the connected single-phase loads and the existing feeder ground protection sensitivity. Single-phase-to-ground-connected loads may be subjected to undesirable overvoltages during ground faults when no grounding is applied. On the other hand, solid grounding of the DR interconnecting transformer can reduce the sensitivity of the existing ground-fault protection to an unacceptable level.

A. No Grounding

With the high side of the interconnecting transformer ungrounded, a line-to-ground fault on the feeder raises the multi-grounded neutral conductor voltage, which is referred to as a neutral shift. The degree of neutral shift depends on fault resistance. Fig. 2 illustrates how the neutral voltage approaches voltage of the faulted phase at fault location as fault resistance reduces. No fault resistance results in line-to-line voltages between the unfaulted phases and neutral in the vicinity of the fault. After the substation feeder breaker trips with DR

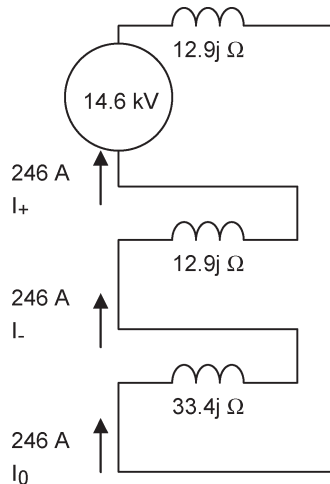


Fig. 3. Ground current for a fault close to POI but without DR (or disconnect open).

still feeding the fault, the entire feeder as well as all the loads connected between the unfaulted and the neutral can rise nearly to the line-to-line voltage when fault resistance and the voltage regulation due to the connected loads are small. These overvoltages would not only cause excessive dielectric stress to the insulation of pole-mounted transformers, which are connected between the neutral and healthy phases, but also severe saturation as their knee-point voltage is typically about 1.05 or 0.05 pu above the nominal operating voltage. Stray flux due to the excessive saturation may damage nonlaminated steel parts of the transformer.

B. Solid Grounding

With the high side of the interconnecting transformer solidly grounded, a line-to-ground fault does not affect the neutral conductor voltage or cause a neutral shift, but it changes the distribution of zero-sequence current. The redistribution of the zero-sequence current is illustrated by applying a line-to-ground fault close to the point of interconnection, as shown in Fig. 1, before and after the DR interconnection.

Fig. 3 shows the Thevenin positive-, negative-, and zero-sequence reactances connected in series for Phase A-to-ground fault on the feeder prior to DR interconnection or with the disconnect at point of interconnection open. As discussed previously, the resistive components of Thevenin impedances are ignored for simplicity and illustrative ease. The total fault current or $3I_0$ contribution from the utility is 738 A. After the DR interconnection, utility and DR both contribute to the fault current, as shown in Fig. 4. The interconnecting transformer is assumed as solidly grounded. The fault current or $3I_0$ contribution from the utility drops to 342 A due to the split of zero-sequence current between utility and DR interconnecting transformer. The contribution further reduces when the DR generator is offline with unit breaker open but with interconnecting transformer connected. This situation is unlikely but possible. With the interconnecting transformer connected and the DR offline, the fault current can be estimated by ignoring or open circuiting the positive- and negative-sequence networks on the

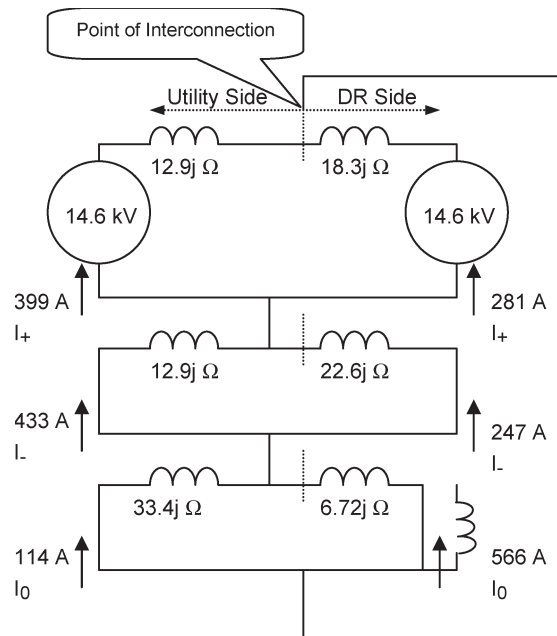


Fig. 4. Ground current with DR generator online and solid grounding on the 25-kV side of the interconnecting transformer.

DR side of Fig. 4. Under this condition, the fault current or $3I_0$ contribution from the utility drops to about 233 A. To complete the discussion, the impact of ungrounded transformer on the ground-fault current is also discussed. In this case, the zero-sequence network on the DR side of Fig. 4 is ignored or open circuited, and, thus, there is no split of zero-sequence current. In fact, the $3I_0$ contribution from the utility increases when the DR is online with ungrounded transformer due to reduced Thevenin positive- and negative-sequence reactances of the system. The $3I_0$ contribution from the utility for this case is about 887 A.

Reduction in fault current from the utility reduces the fault detection sensitivity of the existing feeder protection. As discussed, the worst case reduction is with the DR interconnecting transformer solidly grounded and DR offline. Whereas with an ungrounded interconnecting transformer, there is no concern for sensitivity reduction—rather, it improves the ground-fault sensitivity.

C. Tradeoff

Ungrounding of the interconnecting transformer exposes the feeder and its connected customers to unsafe temporary overvoltages, whereas solid grounding may limit the protection sensitivity to an unacceptable level during ground faults. Impedance grounding can offer a tradeoff. Voltage drop across the grounding (or neutral) impedance limits the neutral shift or voltage rise on the healthy phases during ground faults, as shown in Fig. 2. The grounding impedance of the interconnecting transformer increases the zero-sequence impedance of DR in Fig. 4 and reduces the flows of zero current from the DR side. It, thereby, restricts the reduction in ground protection sensitivity. To summarize, neutral impedance grounding can be used as a compromise because it limits the voltage rise and the reduction in $3I_0$ contribution from utility during ground faults

due to increased zero-sequence impedance of the interconnecting transformer.

BC Hydro accepts, due to DR interconnection, about a 122% temporary overvoltage during line-to-ground faults and about a 5% reduction in feeder ground protection sensitivity from the case with no DR connected. Thus, a solidly grounded neutral is acceptable when the reduction in $3I_o$ contribution from the utility is within 5% of the level with no DR connected on that feeder. When the reduction is more than 5%, the interconnecting transformer is required to have a grounding impedance. The size of grounding impedance is specified (by BC Hydro) to ensure that the temporary voltage rise on the healthy phases during a line to ground is limited to maximum 22%. The grounding impedance is always a reactor, with ohmic value typically from 1.0 to 1.5 times the transformer zero-sequence reactance. It is still possible that even with the use of grounding impedance, which limits the voltage rise to 22%, $3I_o$ contribution from the utility is reduced by more than 5%. In the climate where independent power producers (IPPs) are encouraged, interconnection request cannot be denied on sole basis of “reduction-in-protection-sensitivity.” It means that interconnecting such DR will require enhanced studies, beyond using standard criteria, including reducing the feeder grounding protection settings and recoordination with downstream fuses. As a result, the interconnection cost may also increase.

IV. “TWO-TO-ONE” RULE

The interconnection cost includes all upgrades within the utility system for the sole benefit of evacuating power from the DR generator. Since the size of DR generator is generally small, typically less than 10 MVA, the high interconnection cost of small generators may obliterate the economic viability of such projects. Section II discussed distribution upgrades outside the substation fence. The next section will discuss system or protection upgrades inside the local or remote-utility substations. Interconnecting a DR requires the distribution system, which is designed to serve radial load, to accommodate two-way flow of power. Thus, protection upgrades can form a sizable share of the interconnection cost. BC Hydro pioneered a “two-to-one” rule [3], which permits interconnecting smaller DRs at lower cost. As a cautionary note, the rule should not be extended to large transmission connected generators.

The “two-to-one” rule is based on a premise that an island with the connected load twice as much as the islanded generation is not sustainable. Equation (1) below, which is a solution of the swing equation, can illustrate the frequency decline in a generation-deficient island.

$$\Delta f = \frac{\Delta P}{D} \left(1 - e^{-Dt/2H}\right) \quad (1)$$

where

- Δf per-unit frequency change from starting frequency;
- ΔP per-unit generation deficiency or generation minus load divided by generation (ΔP is negative in generation-deficient island);
- D load-damping factor or ratio of percentage load change to percentage frequency change;
- H system’s inertia constant.

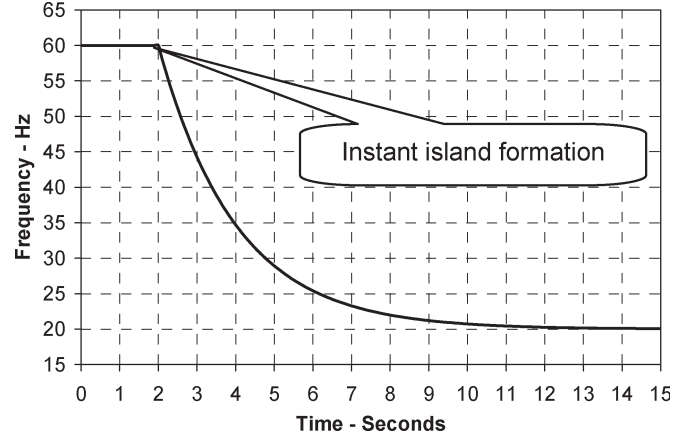


Fig. 5. Frequency decline when an island is formed with load twice as much as generation, and assuming load damping and inertia constant as 1.5.

As per this equation, the rate of frequency decline mainly depends on the inertia constant and load damping. As the frequency declines, the outputs of the rotating loads such as induction motors reduce. This reduction in load as the frequency declines is referred to as load damping, which starts to compensate for generation deficiency. Fig. 5 shows the frequency profile when an island with generation deficiency was formed at 2 s. At the instant island formation, the load was twice as much as the generation or ΔP was -1 pu. Both H and D were assumed as 1.5. The frequency of the island dropped by 10 Hz in about 0.6 s and 20 Hz in about 1.4 s after the formation of the island, indicating a fast collapse of the island frequency.

Based on the “two-to-one” rule, BC Hydro assumes that a DR will collapse on its own without intervention from utility’s protection or control systems when it separates and forms an island with load at least twice the connected generation. This islanded DR poses no threat to the utility infrastructure and customer installations. The “two-to-one” rule allows reconnecting the island to the utility system with no special supervision or monitoring.

V. SYSTEM UPGRADES FOR DR INTERCONNECTION

BC Hydro substations are built to withstand the ultimate short-circuit levels, and increases in fault levels from DR addition are unlikely to impact current transformer performance and equipment ratings, such as for circuit breakers. Further, a DR typically displaces the substation load, and, thus, it is also not likely to impact the substation-equipment steady-state ratings. Nevertheless, the effect of DR on utility fault level or reverse power flow under maximum export conditions from DR should still be checked to determine if substation-equipment upgrades are needed.

Breaker tripping initiated by the existing protection system, under faults and abnormal conditions, can island DR with utility loads. Protection upgrades may be necessary to make sure that DR isolates without posing any risk to public, customers, utility equipment, or its own safety under these conditions. An island is most likely to occur following to breaker trips initiated by protection operations under faults or abnormal

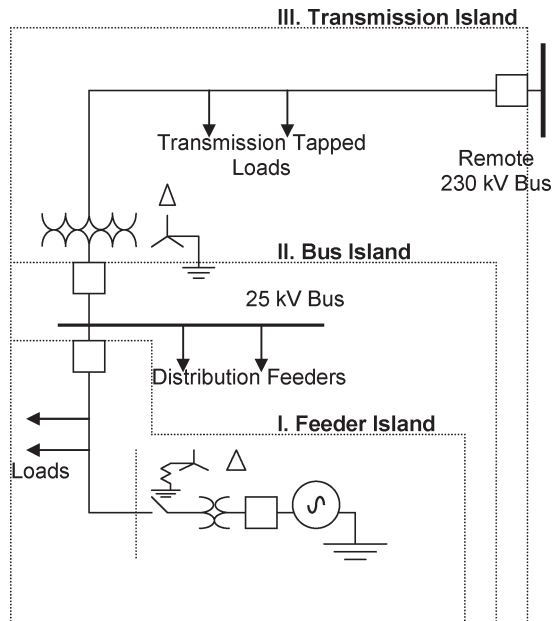


Fig. 6. Various locations where the DR can form an island with utility loads.

operating conditions. Typically, planned or supervisory opening of the breaker avoids islanding by prior isolation of DR from the system. The DR can form an island with utility loads at various locations. For the system considered in this paper, Fig. 6 shows three possible locations, where the DR can form an island with the utility loads. These islands are referred to as feeder, bus, and transmission islands with the feeder being the smallest and the transmission as the largest island. Using the “two-to-one” rule, this section discusses sustainability of these islands and the associated protection or equipment upgrades. It is important that analysis be done considering the smallest island at the feeder level. If there are no protection concerns for the smallest island, protection issues for the next larger island are not applicable. Also of importance, if protection changes for the smallest island are required, then these changes are also applicable and will remain even if there are additional protection aspects that must be considered for larger islands.

A. Feeder Island

A feeder island forms when the DR isolates from the utility system due to tripping of a breaker on the feeder to which the DR is connected. For convenience, the feeder to which the DR is connected will be referred to as the DR feeder in the rest of this paper. The “two-to-one” rule is applied using the minimum load on the DR feeder and maximum DR generating capacity. In the absence of the measured load data, BC Hydro uses an annual minimum load as 25% of the annual feeder peak load. Feeder island is assumed as nonsustainable when the minimum load on the DR feeder is more than twice the maximum DR generating capacity. Should protection initiated trips separate such a small DR from the utility system, the DR will shut down or become deexcited on its own due to fast declining frequency (and voltage) even when its own protection is unable to detect the fault, which initiated breaker tripping. After separation, the lost load on the DR feeder can be restored using automatic

reclosing or supervisory close without any concerns of DR being online. Thus, a DR can interconnect without any upgrade in the BC Hydro substation or transmission system if its size is small enough that it cannot form a sustainable island using the “two-to-one” rule during the minimum feeder load and maximum generation conditions.

If the DR is capable of forming a sustainable feeder island or as per “two-to-one” rule when the minimum feeder load is less than twice the DR rating, it may require the following system upgrades.

- 1) If the DR feeder is equipped with a substation circuit recloser, replace the recloser with a circuit breaker.
- 2) Add a three-phase voltage transformer (VT) on the load side of the DR feeder breaker to allow voltage supervision or sync-check on restoration.
- 3) Replace the existing protection with modern multifunction relay equipped with features such as voltage supervision, sync-check, directional overcurrent element, out-of-step detection, and disturbance monitoring.

The existing substation feeder circuit reclosers are not acceptable because their built-in protection features are not suitable for DR interconnection. Further, they may not be capable of interrupting with the sources on both sides of the poles, and their trip-coil rating may be too low. Load-side VT and multifunction relay with deadline logic (voltage supervision) are required to prevent out-of-sync closing of the DR generator and the utility system during auto or manual or supervisory restoration of the feeder loads. Load-side VT and deadline logic are not required when:

- 1) DR is connected to an express feeder with no BC Hydro loads (with no autoreclosing);
- 2) DR is connected to an underground cable feeder, i.e., control center operator will not close the feeder breaker before cable inspection after tripping.

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

Under certain credible contingencies when the in feed from DR is strong and the utility system is weak, the protection on the DR feeder may miscoordinate for a fault on an adjacent feeder. Reverse fault current in the DR feeder and forward fault current in the adjacent faulted feeder may nearly be the same, resulting in simultaneous trips of both feeders. Avoidance of this problem may either require protection recoordination or directionalizing the protection on the DR feeder. A similar problem can be encountered in fuse saving schemes, where the DR 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 saving scheme cannot be applied or the ground instantaneous protection may require directionalization or desensitization.

The impact of the interconnecting transformer grounding on the feeder ground protection is already discussed in Section III.

Section VI will address issues associated with out-of-step detection and tripping.

B. Bus Island

A DR is capable of forming a sustainable bus island per “two-to-one” rule when the minimum bus load is less than twice the DR rating. An Interconnection of such DR may require the following protection upgrades.

- 1) Extend bus protection tripping: Since the DR can feed utility-bus faults, bus protection should include tripping of the circuit breaker on the DR feeder to prevent back feed from DR to fault.
- 2) Revisions to bus protection ct circuits: Proper protection practices would dictate that bus protection ct connections include DR feeder to account for in-feed from DR source. The benefits of this need to be assessed carefully because the cost of extending the ct connections may be significant. Further, if the bus protection is inverse-time overcurrent and backs up the feeder protection, extending the bus protection to net-out in feed from the DR source will negate this benefit.
- 3) Performance of utility relaying in an island: With the reduced fault levels in the island, the performance of the utility relaying must be assessed.
- 4) DR detection of utility feeder breaker failure: For a feeder breaker failure for a feeder fault, the normal utility practice is for the breaker-failure protection to back-up trip the associated bus section. With the DR resource connected, this could still theoretically be supplying fault current to the bus fault. Solutions include ensuring that the DR resource can detect a bus fault or the DR feeder breaker-failure protection initiates a direct transfer trip to the DR.

C. Transmission Island

A DR is capable of forming a sustainable transmission island per “two-to-one” rule when the minimum load on the transmission line feeding to the distribution substation to which the DR is connected is less than twice the DR rating. A sustainable transmission island will necessitate line protection at the distribution substation to isolate fault current in feed from the DR. Primary and standby line protections for phase faults as well as time delayed zero-sequence overvoltage protection for line-to-ground faults will be required. The time delay on the zero-sequence overvoltage protection must be properly coordinated to ensure that it does not operate for out-of-zone faults. Standby phase and ground protections can be eliminated if the transfer trip from the remote terminal is required to address temporary overvoltage concerns, as discussed in Section VII. Addition of line protections may require new high-voltage line cts and vts if they do not exist.

VI. OUT-OF-STEP DETECTION AND TRIPPING DUTY

A DR and utility system operating in parallel may go out of step and swing against each other under certain con-

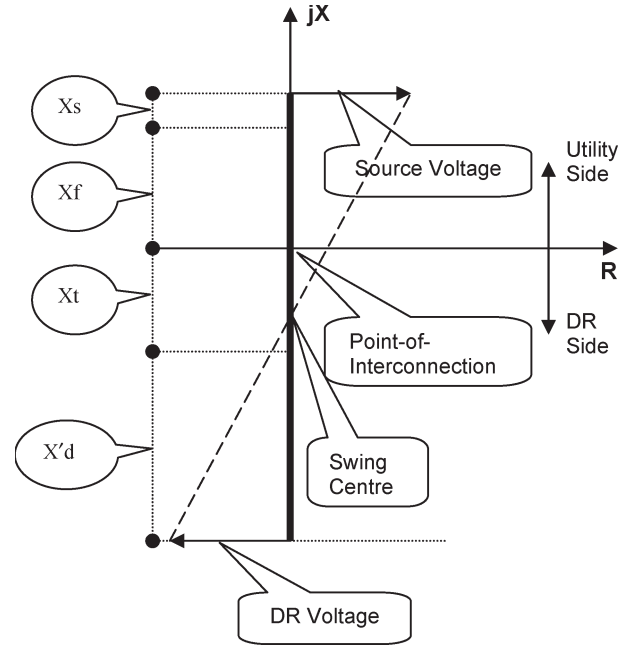


Fig. 7. Identifying swing center between utility and DR systems using per unit impedances on $R-X$ diagram.

tingencies. The cost of full dynamic simulations to identify out-of-step conditions and location of swing center is not justified for assessing the DR interconnection requirements. Instead, a simple method is used. In this method, the positive-sequence impedances of the utility source at low-voltage bus (X_s), distribution feeder (X_f), interconnecting transformer (X_t), and DR generator (X'_d) are plotted on the $R-X$ diagram. The use of a positive-sequence Thevenin 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 utility system. Fig. 7 shows the $R-X$ diagram with the origin being the point-of-interconnection (POI), with the positive reactive axis representing the total impedance on the utility side ($X_s + X_f$), and negative axis representing the DR side ($-X_t - X'_d$).

The location of the swing (or electrical) center can be estimated from the $R-X$ diagram by assuming that the utility and DR voltages behind the source impedances are equal and opposite. The swing center is midway on the impedance line between two sources, as shown in Fig. 7. In most cases, the sum of the DR and interconnecting transformer impedances is much larger than the sum of the feeder and utility-source impedances. The swing center typically lies on the negative X -axis. Therefore, out-of-step protection in general, if required, is part of the DR generator or interconnecting transformer protection rather than the utility interconnection protection requirement. However, if the swing center is within the utility system or on the feeder but close to the utility source, the out-of-step protection becomes part of the utility interconnection requirement and it can be included in the new multifunction relay for the feeder protection, as discussed in Section V.

Proximity of the swing center to the utility source and its detection by the feeder protection requires tripping of the feeder breaker to separate the utility system and the DR. Since the

utility distribution system was designed for radial source, the feeder breaker may not be rated for out-of-step trip duty. The two voltage sources (utility and DR) across the feeder breaker are expected to be close to 180° out-of-phase when out-of-step tripping is initiated. Voltage sources in antiphase impose twice transient recovery voltage (TRV) compare to a single source (no DR). A breaker not rated for out-of-step trip duty may restrike (or reignite) and fail. However, replacing the feeder breaker, as part of interconnection requirements, may rule out financial viability of the DR. To avoid feeder-breaker replacement, BC Hydro accepts out-of-step tripping delayed beyond first pole slip or trip-on-the-way-out [4] to ensure that the two voltage sources are not in antiphase when the breaker poles begin to part. Delayed tripping reduces TRV stress on the breaker, and thereby avoids its replacement. However, delayed tripping requires that the DR must be capable of withstanding at least one pole slip without damage to its generator rotor shaft.

VII. TRANSIENT OVERVOLTAGES AND TRANSFER TRIP

As discussed in Section III, a line-to-ground fault on distribution feeder can raise voltages on the healthy phases to line-to-line level after tripping of the utility feeder breaker when it has DR connected via ungrounded interconnecting transformer. These overvoltages can be much higher than line-to-line level, when the DR becomes the only source back feeding into a line-to-ground fault on an ungrounded transmission system. Referring to Fig. 6, a line-to-ground fault on the transmission system will trip the remote-utility line breaker first as there is no zero-sequence current from the DR to the fault due to the delta-connected high side of the distribution-station transformer. Time delayed zero-sequence overvoltage protection on the line terminal at the distribution substation (as discussed in Section V) will isolate the DR. In the time duration after tripping of the remote-utility terminal (which provides effective grounding to the line) and before isolation of the DR, the DR is the only source connected to the line-to-ground fault on an ungrounded transmission system. Overvoltages on the healthy phases for this duration can rise to much above line-to-line voltage if the inductive reactance of the system under weak source condition exhibits low-frequency series resonance with the zero-sequence line capacitance of the transmission line. The system inductive reactance comprises of the positive and negative sequence reactances of the DR generator, interconnecting transformer, distribution feeder, utility distribution 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 a near-60-Hz series resonance is strong.

The severity of the overvoltage due to the series resonance along with the neutral shift for an ungrounded system during a line-to-ground fault depends on many factors, such as load (higher load reduces the overvoltage), fault location, line length (a longer line can have higher overvoltage), and fault resistance (resistance reduces the overvoltage). Detailed Electro-Magnetic Transients Program (EMTP) studies may be necessary for the accurate assessment of these overvoltages. However, steady-

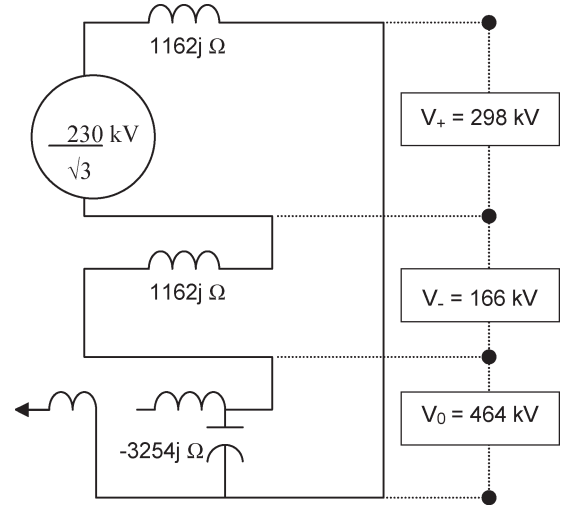


Fig. 8. Sequence network for a line-to-ground fault at the remote terminal of the transmission line but with the remote breaker open.

state 60-Hz short-circuit programs, which include line capacitance into the model, can provide a rough estimate. Fig. 8 shows the Thevenin positive-, negative-, and zero-sequence reactances of the system with configuration similar to those in Fig. 6. The Thevenin reactances are obtained, using the steady-state short-circuit program, for a line-end ground fault on Phase A with the remote terminal open. Details of line and source data used in modeling are given in the Appendix, except that resistive components of all impedances were ignored. Notice that the zero-sequence network has only charging capacitance because the transmission network is connected to the delta-connected transformer. During a line-to-ground fault, inductive positive- and negative-sequence reactances of the entire system are in series with the zero-sequence capacitive reactance of the line. The series-resonance frequency of the system for the sequence reactances, as shown in Fig. 8, is about 71 Hz. A rough estimate of the voltage on the healthy phase or Phase B at the fault location is given by

$$V_b = V_0 + a^2 V_+ + a V_- \quad (2)$$

which is about 706 kV. The voltage at the distribution substation will be slightly higher due to the voltage drop from the capacitive current along the line. Appendix gives Phase B voltage waveform at the distribution substation obtained using the detailed EMTP simulations. The maximum is about 1250-kV peak or 883-kV rms value when surge arresters, transformer saturation, and load damping were ignored. Detailed EMTP simulation, which incorporates these effects, will show that the voltage rise will be limited to the protective level of surge arresters.

The temporary overvoltage is both a protection issue (station-equipment damage) and a power-quality issue (customer-equipment damage). In BC Hydro, these overvoltages have usually been prevented by delaying the tripping at the BC Hydro remote line terminal(s) and sending a transfer trip to the substation-feeder circuit breaker to which the DR is connected. The intent is to disconnect the DR from the faulted transmission

line before the remote protection trips its own breaker and to avoid having DR as a sole source feeding to a line-to-ground fault on an ungrounded transmission system. These overvoltages must be evaluated for all DR interconnections using the simple approach with steady-state short-circuit model, which includes line shunt capacitance. Should this approach indicate any overvoltage concerns due to series resonance, detailed EMTP simulations incorporating the system load, surge arresters, and magnetizing saturation must be performed to assess the requirements of transfer trip from the remote terminal to the DR-feeder circuit breaker in the BC Hydro substation.

Transfer trips are not required for station-equipment protection with the following conditions.

- 1) All transmission surge arresters are rated for use on an ungrounded system.
- 2) There is no series-resonance condition.
- 3) Surge arresters can withstand the overvoltage until the proposed time-delayed zero-sequence overvoltage line protection (discussed in Section V) at the distribution substation operates.

VIII. DR CONTROL AND VISIBILITY

BC Hydro requires no operating control over nonutility DR connected to the distribution system at 35 kV and below.

DR ratings from 1 to 10 MVA are required to provide operating data and interconnection status to the BC Hydro Area Control Centre. DR data are plant MW, MVar, MWh, and kV via unsolicited (DR initiated) report by exception using a dial-up Intelligent Electronic Device (IED) with Distributed Network Protocol (DNP) 3.0; 2-min maximum to establish connection for BC Hydro interrogation on demand via telephone analog business line with entrance protection; and no other telecom uses in the DR plant.

For DR ratings over 10 MVA, the DR operating data required include unit MW, MVar, MWh, and kV, plus unit connection status and unit running status. This is a real-time report by exception using an IED with DNP 3.0 Protocol and a single dedicated (always on) communication link, i.e., telephone lease, power line carrier, fiber optic, microwave, etc.

IX. REVENUE METERING

The point-of-delivery/receipt (PODR) is the power custody transfer point and is typically located at, or near, the POI to the distribution system. The revenue metering is located at the Point-of-Metering (POM). Subject to approval by BC Hydro, the POM may be on either the BC Hydro side of the power transformer(s) or the DR side of the power transformer(s). When there are multiple power transformers, the POM is generally on the BC Hydro side of the power transformers to avoid multiple POMs. Where the POM is on the BC Hydro side of the power transformer(s), it shall be on the DR side of the service-entrance disconnect device. Where the POM is on the DR side of the power transformer, a disconnect device shall not be installed between the power transformer and the POM. This is to insure that no-load losses are correctly registered whenever the power transformer is energized. If the POM is not

located at the PODR, a loss-compensation calculation is applied to account for the losses between the POM and the PODR.

X. CONCLUSION

This paper presented BC Hydro's approach to DR interconnection. A DR connected to the utility system via ungrounded interconnecting transformer can expose the utility and its customers to unacceptable high voltages during ground faults. Solidly grounded interconnecting transformer can reduce the sensitivity of the existing DR-feeder ground protection sensitivity to unacceptable level. As a tradeoff, BC Hydro typically specifies high-impedance grounded interconnecting transformers, which would limit the temporary voltage rise below 22% and the reduction in ground protection sensitivity below 5%.

BC Hydro pioneered a "two-to-one" rule, which is only used for generators interconnecting to the distribution system. The "two-to-one" rule states that the DR will shut itself down, without intervention from the utility protection, when it separates from the utility system with the load twice as much as generation in the island. No system or protection upgrades are necessary in the BC Hydro substation or transmission system, when the DR is the sole source feeding into fault after it separates from the system due to trips initiated by the protection within the utility system, as long as the expected minimum load in the island is twice the DR-generation capacity. This rule is applied considering the smallest island at the feeder level; if there are no protection concerns for the smallest island, protection issues for the next larger island are not applicable.

This paper also discussed BC Hydro's practice of delayed tripping during the out-of-step conditions to ensure that the existing feeder breakers are not subjected to excessive TRV due to the two sources in the antiphase across the breaker poles. Finally, the paper provides an insight into a series-resonance phenomenon that can occur when the DR back feeds to a ground fault on an ungrounded transmission system. Utility system and its customers can be subjected to overvoltages higher than line-to-line levels due to this phenomenon. Avoidance of series resonance requires delaying the line tripping at the remote terminal and sending a transfer trip to the BC Hydro substation DR feeder breaker. It ensures that the DR is isolated from the system before tripping of the remote line terminal(s), which provides an effective grounding to the transmission system. Detailed EMTP simulations may be required to accurately assess the requirement of remote transfer trip. Since EMTP simulations are involved and time consuming, a simple approach using the Thevenin impedances from the steady-state short-circuit program can be used to assess the overvoltage concerns due to the DR interconnection. Should this simple approach indicate a possibility of series-resonance phenomenon and associated overvoltages, a detailed EMTP study can be undertaken.

APPENDIX

EMTP was used for simulating temporary overvoltage on the 230-kV side of the distribution terminal due to a line-end Phase-A-to-ground fault on the ungrounded transmission line.

TABLE I
MODEL PARAMETERS FOR EMTP SIMULATIONS

Model	Parameter	Value
25.2 kV Source	Z+	$0.36 + 5.8j \Omega$
	Z0	$1.97 + 22.6j \Omega$
Distribution Transformers ①	Ratio	25.2/230 kV
	Rating of each	9 MVA
	Connection	DYg
	Impedance	9%
230 kV Line	Z+	$11.7 + 70j \Omega$
	Z0	$36 + 207j \Omega$
	Y+	$443.4j \mu s$
	Y0	$315j \mu s$
	Length	137 km

①Two transformers in parallel with total 18 MVA ONAN rating and 31.8 MVA force rating. The 25 kV or Wye side solidly grounded.

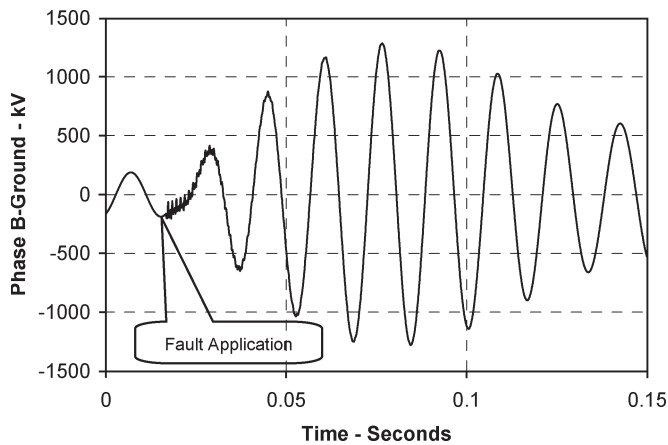


Fig. 9. Temporary overvoltages at distribution-station terminal for a ground fault on an ungrounded transmission line.

The system configuration was used similar to what is shown in Fig. 6 except that two parallel distribution transformers were used. Table I provides detailed data used in the simulation. Transformer winding configurations were delta on the 230-kV side and solidly wye grounded on the 25.2-kV side. DR was about 34 MVA and connected with express or dedicated feeder to the station distribution bus. As discussed before, the present BC Hydro practice does not allow wires bigger than trunk-line standard of 336 kCM ASC, which limits the upper level for aggregate DR on a distribution feeder to about 15 MVA. The distribution bus was modeled using the ideal 25.2-kV source with Thevenin impedances representing the DR, interconnecting transformer, and feeder impedances. Ideal transformers with no magnetizing branch were modeled. Line surge arrestors or loads were also ignored in the modeling. However, the 230-kV line was modeled in detail using a transposed distributed line model. A line-to-ground fault was applied at 16.6 ms at the remote terminal, but with that terminal open. Fig. 9 shows the voltage waveform on the healthy phase at the distribution substation. The maximum voltage is about 1250-kV peak or 883-kV rms. This overvoltage is not practical as it would be limited by the protective level of surge arrestor, magnetizing saturation, and damping from the resistive component of load, all of which were ignored in this simulation.

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