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# Enhancing Distributed Energy Resource Integration and Supply Reliability

## The Two-to-One rule.

SOCIETY'S INCREASING DEPENDENCE ON small renewable resources, generating less than 10 MVA, for sustainable electricity brings forth a unique challenge. Unlike large and centralized generation facilities, these resources often remain unconnected to the transmission system because there are prohibitive costs associated with high-voltage interconnection equipment. Consequently, they find their connection in medium- or low-voltage distribution systems, originally designed for customer supply rather than for securing the integration of generation resources. This shift transforms the distribution feeder from a single source to a double-sourced (or multisourced) line, necessitating protection requirements like the transmission system. However, traditional transmission protection solutions prove too costly to integrate these small-generation resources into the distribution system.

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### Navigating Distributed Energy Resources

BC Hydro has introduced a novel protection philosophy, the "Two-to-One Rule," designed to assess and optimize the protection upgrades essential for connecting distributed energy resources (DERs) to the distribution system. Operating on the principle that an electrical island comprising twice as much load as generation is unsustainable, this rule eliminates the need for additional anti-islanding protection on the distribution feeder. Over the last two decades, BC Hydro has successfully connected more than 100 small renewable resources to its distribution system, thanks to the economic viability provided by the application of this rule.

This article navigates the landscape of DER integration, beginning with exploring protection issues and demonstrating the Two-to-One Rule in action. It delves into the protection upgrades necessary for securing these resources alongside customer loads in a microgrid,

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post separation from the utility grid. The article further presents a compelling case study of battery storage integration with a 25-kV distribution feeder, showcasing the optimized protection through the new rule and the enhanced supply reliability achieved by enabling the storage system to function as a microgrid with a remote community.

## DER Benefits

The utility gains substantial advantages by allowing small DERs to operate in islanded mode with local loads or as microgrids:

- *Economic benefits*: Local generation becomes a strategic tool for deferring network upgrades, avoiding overloading, especially during peak load hours, and reducing transmission losses.
- *Power quality*: Local generation resources can enhance voltage regulation, particularly in a weak supply network.
- *Reliability*: The operation of microgrids significantly improves supply reliability, either during forced or planned network outages.

## DER Protection Issues

Integrating DERs poses unique protection challenges, transforming a conventional radial distribution line into a networked system resembling a transmission line. However, the cost associated with traditional transmission protection solutions often renders the integration of DERs economically unfeasible. To address this issue, in the early 1990s, BC Hydro introduced an innovative protection philosophy known as the Two-to-One Rule, which offers a quantitative approach to determine the minimum protection upgrades necessary to connect the smaller generation resources to the distribution system safely. A similar rule is also discussed in the IEEE-1547-2018 standard, emphasizing its relevance and acceptance in the industry.

The Two-to-One Rule is founded on the premise that an electrical island, formed when a DER separates and the load is at least twice the maximum power output rating of the DER, is inherently unsustainable. This island collapse is rapid and poses no significant threat to the utility or the public, even during short circuit conditions within the island. After the fault is isolated or repaired, the DER can be seamlessly reconnected. The rule ensures a considerable imbalance between resource power output and load, guaranteeing a swift collapse of the island.

Figure 1 is a simplified one-line diagram of an active distribution network with a DER integrated into the distribution substation. After introducing the DER, as shown, the trips from the protection systems can form three possible islands: a feeder island, a bus island, or a transmission island, depending on which breaker opens to disconnect the utility supply.

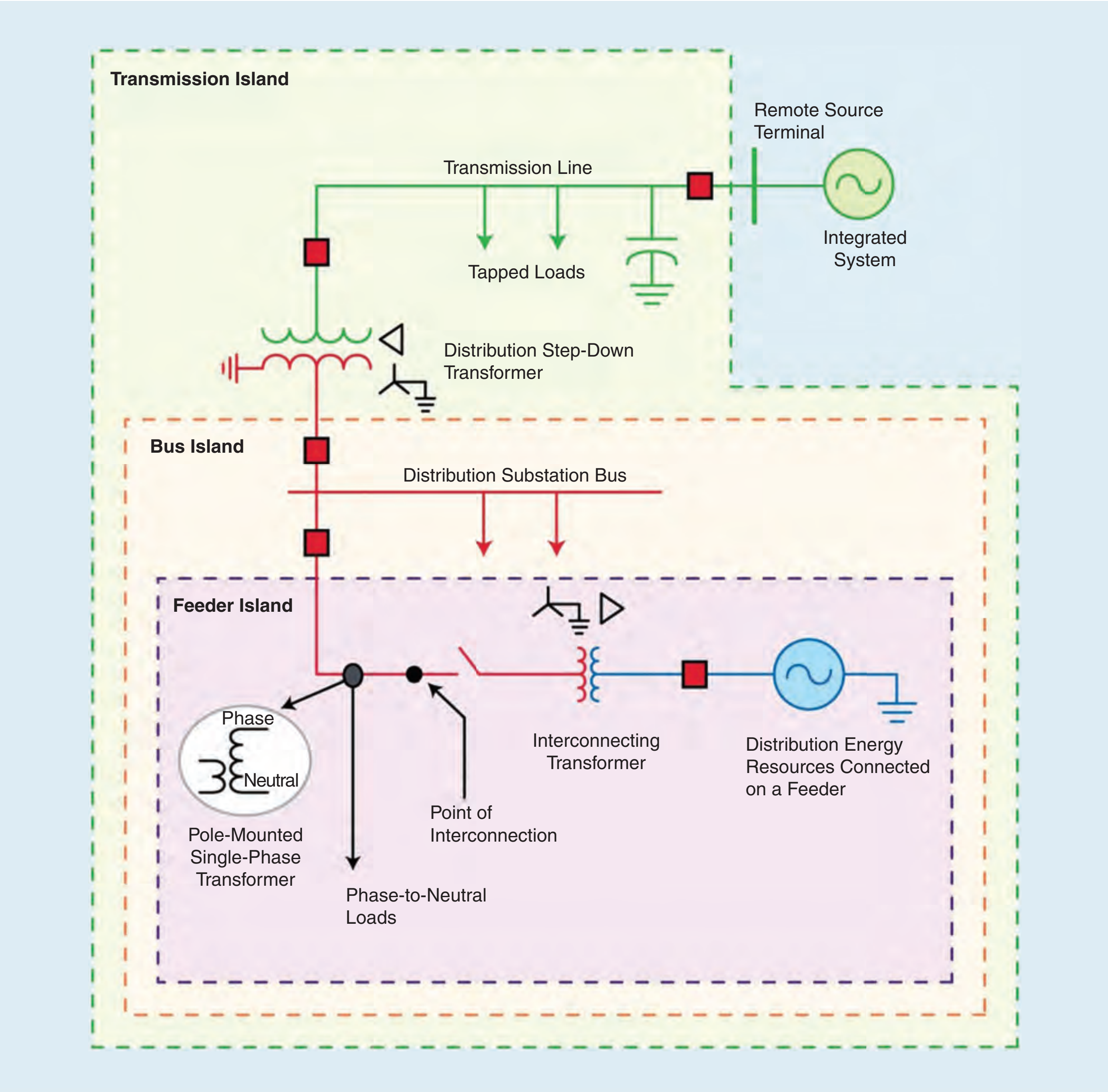


**Figure 1.** A simplified one-line diagram of an active distribution system.

### Feeder Island

A feeder island materializes when the DER disconnects from the utility because of automatic tripping or manual opening of the associated feeder breaker. Following the Two-to-One Rule, a feeder island is deemed unsustainable if the feeder's minimum load exceeds twice the maximum DER's generation capacity. BC Hydro employs an annual minimum load criterion, providing a robust margin for island resource deficiency, ensuring a self-induced shutdown due to a rapid decline in frequency and voltage. Once the DER shuts down, the short circuit is no longer a risk. In case of transient or self-clearing faults, the disconnected load on the resource feeder can be restored with automatic reclosing (or supervisory closing) without any concern of out-of-synchronism conditions. BC Hydro uses a 30-s automatic reclose time, which is proven to be long enough for the resource to collapse and shut down. A resource can connect without substation or transmission protection upgrades if total generation can't form a sustainable island using the Two-to-One Rule.

For sustainable feeder islands, the feeder protection upgrades typically include the three-phase voltage transformer and a modern multifunction relay, facilitating voltage supervision, synch check, directional overcurrent protection, out-of-step detection, and disturbance monitoring.

**BC Hydro has introduced a novel protection philosophy, the "Two-to-One Rule," designed to assess and optimize the protection upgrades essential for connecting DERs to the distribution system.**

### Bus Island

A bus island occurs when a low- or high-side transformer breaker opens. The Two-to-One Rule dictates that a bus island is unsustainable if the minimum bus load surpasses twice the combined DER capacity connected to that bus. Corrections for an unsustainable bus island involve no changes beyond those addressed for the feeder island.

In the case of a sustainable DER in a bus island, potential risks arise from its ability to feed short circuit current after separation from the utility system. Mitigating this concern necessitates extending the bus or transformer protection tripping zone to disconnect the short circuit fault contribution from the DER.

### Transmission Island

A transmission island emerges when the line end at the remote source terminal opens while the DER remains connected, back-energizing the transmission line. According to the Two-to-One Rule, a transmission island is unsustainable if the minimum load on the distribution substation's transmission line exceeds twice the maximum combined DER capacity connected to the substation. The rule avoids additional transmission line protection equipment installation for unsustainable transmission islands.

However, a sustainable transmission island requires new and expensive transmission line protection equipment and instrument transformers (current and voltage transformers). Careful consideration of these aspects is crucial in ensuring the reliable, safe, and secure integration of DERs into the distribution system.

## Microgrid Protection Issues

In enhancing the distribution customer supply reliability, implementing microgrids with DERs presents notable advantages. A transmission island resulting from a DER may lead to an ungrounded transmission line. Operating such lines with tapped loads is typically discouraged due to inherent risks, rendering them unsuitable for microgrid applications.

Upon disconnecting DERs from the utility grid, establishing stable feeder islands or bus islands capable of operating as microgrids becomes feasible. This microgrid functionality proves essential in sustaining power supply to local loads until utility restoration. However, achieving this requires a nuanced approach to protection and control. This section delves into critical protection considerations associated with stable microgrid operation post separation from the utility system, addressing the challenges and solutions in ensuring both safety and power quality for consumers.

### Selectable Setting Groups

In microgrid scenarios, local generation may lack the capacity to produce sufficient short circuit fault current. To address this, microprocessor-based relays offer the flexibility of selectable setting groups. This adaptive approach ensures that protection settings align with the demands of microgrid operation with low short circuit fault currents, offering increased sensitivity compared to conventional integrated system settings.

Modern DERs connect to the grid through the power electronics inverters. These resources are low-inertia generators requiring readjustments to the inverter controls to supply unbalanced load currents. Microgrids with modern DERs can have challenges maintaining voltage and frequency within the power quality standards. Selectable controls are required to achieve acceptable supply quality.

### DER Grounding

North American distribution feeders are four-wire, three-phase feeders with a multigrounded common neutral conductor. The station is connected to the transmission system via a delta-wye substation transformer. The wye side on the distribution voltage is solidly grounded at the substation, which provides an effective neutral grounding for the loads connected to the distribution feeder. Each feeder's fourth or neutral wire has multiple grounds, allowing single-phase loads to be connected between phase and neutral via pole or pad-mounted transformers rated for line-to-neutral voltage.

A DER connects to the feeder through a unit transformer. The wye side on the distribution feeder and delta side on the generation resource are preferred choices for the DER transformer. However, grounding the wye side involves the protection and ground safety tradeoff, as discussed here.

*An ungrounded distribution resource in a microgrid subjects pole and pad-mounted single-phase transformers to line-to-line voltage.*

#### Solid Grounding: Protection Desensitization

A solidly grounded wye side of a DER maintains the grounding when the resource and the utility loads operate as a microgrid—for example, after separation from the utility system. In the grid-connected mode, the solidly grounded wye side splits the fault current between the two ground paths established by the station and DER transformers. This split desensitizes the feeder ground protection at the utility station and the DER. When the utility source is weak, and the DER is relatively strong, desensitization may compromise the feeder ground protection's ability to provide adequate primary ground fault protection or backup to the feeder's downstream protection device.

#### Ungrounding: Temporary Zero Sequence Overvoltage Risk

The feeder protection desensitization in grid-connected operation can be eliminated by leaving the wye side ungrounded, which does not allow resource operation in the microgrid mode. An ungrounded distribution resource in a microgrid subjects pole and pad-mounted single-phase transformers to line-to-line voltage. It severely saturates them or can damage them during single-phase-to-ground faults. It can also expose the utility and its customers to unacceptably high voltages.

#### Reactance Grounding: A Compromise

Reactance grounding is a compromise between solid and no grounding of the neutral of the unit transformer interconnecting the DER to the distribution feeder. Typically, the neutral grounding reactance is limited to 1 to 1.5 p.u. times the leakage reactance of the transformer. It reduces protection desensitization in the grid-connected mode. It helps maintain effective grounding in microgrid mode; i.e., it limits the overvoltage to 1.4 p.u. during ground faults.

### Additional Considerations

Numerous intricacies in microgrid operations need attention, encompassing measures such as preventing out-of-synchronism occurrences, blocking online tap changers during reverse flows, and avoiding incorrect trips in sensitive protection following extended outages. Additionally, microgrid operations must adhere to all obligatory regulatory requirements.

- *Out-of-synchronism close*: A transition from a microgrid to a grid-connected mode by closing any substation or transmission breaker with the DER connected poses the risk of an out-of-synchronism close. Synchronizing or synch-check facilities across all closing breakers are required to avoid this risk.
- *Bidirectional power flow*: Bidirectional power flow through feeder voltage regulators and transformers leads to incorrect operation of online tap changers, affecting voltage regulation. The online tap changers can be blocked for reverse flow through them.
- *Cold-load pickup strategy*: The sensitive overcurrent protection settings used are due to weak short circuit strength with the microgrid. The phase overcurrent protection settings can misoperate when the entire feeder load is picked up during the black-start operation. Feeder recloser preferably controlled through supervisory control and data acquisition, are required to energize the feeder load in steps.
- *Regulatory compliance*: The microgrid design may require compliance with local or international standards.

### A Microgrid

In July 2013, BC Hydro strategically deployed a feeder microgrid system to address challenges related to sustained power outages in a remote community. The primary objectives were to bolster supply reliability during outages and mitigate distribution substation demand concurrently, thus deferring the need for a costly station transformer replacement.

The microgrid system, featuring a 1-MW, 6.5-MWh battery storage installation, was pivotal in achieving these dual goals. Reliant on a single 25-kV distribution feeder spanning 56 km, the community faced persistent and prolonged power outages. The geographical layout of the feeder, illustrated in Figure 2, demonstrates the challenging terrain and environmental conditions, such as falling trees, that contributed to frequent disruptions. Moreover, the feeder's proximity to a railway line added complexity, necessitating coordination with train schedules for repair activities.

**The recorded fault illustrated that negative sequence relaying, as a fault or directionality detector, is not reliable in microgrids sourced by inverters.**

### Battery Storage Connection

Figure 3 is a one-line diagram of the distribution feeder and its connection to the battery storage system. The system, consisting of two 500-kW battery modules or 1 MW consolidated, operates within a voltage range of 485–780 Vdc. Integration into the distribution feeder is facilitated through a 1.25-MVA inverter and associated control, collectively forming the Smart Storage Management System (SMS). The connection to the distribution feeder includes a delta-wye-grounded transformer, with the wye-grounded winding on the 25-kV feeder side. This configuration ensures effective grounding of the 25-kV system during microgrid operation. However, it introduces zero sequence ground overcurrent protection desensitization, determined to be less than 10% when the battery storage operates in parallel with the grid. Meeting BC Hydro's desensitization requirement of less than 10% is vital to preserve the feeder protection's ground fault detection sensitivity at the stations.

The integration point of the storage system to the feeder includes a fault sensing and interrupter device known as the *IR*. Strategically positioned on the station side of the feeder, the IR plays a vital role in detecting faults and facilitating intelligent control. The IR and the SMS communicate through a reliable 900-MHz radio link, enabling seamless teleprotection and control signal exchange.

Anti-islanding protection, encompassing voltage and frequency protection functions as per IEEE Standard 1547-2018, is integral within the SMS. It trips the inverter system offline as a last line of defense, preventing backfeeding into distribution system faults. Feeder protection in the substation or reclosers along the feeder is coordinated for feeder faults using a time-overcurrent mechanism. Anti-islanding protection also ensures the disconnection of the storage system to facilitate auto-reclose attempts by the feeder protection.

### Substation Protection Upgrade

The historical minimum feeder load is less than 2 MW, confirming the sustainability of the feeder island under the Two-to-One Rule. A three-phase voltage transformer was introduced on the load side of the feeder breaker at the station. To enhance protection measures, the existing electromechanical feeder protection underwent an upgrade with the installation of modern multifunction feeder protection. This upgraded system incorporates a synch-check function, preventing any out-of-synchronism closing of the feeder breaker.

The minimum load on the bus is around 5 MW, indicating that the bus island is not sustainable. As a result, no additional protection upgrades are deemed necessary for the bus island or transmission island scenarios.

### Grid-Connected and Microgrid Modes

The storage system operates in the grid-connected and microgrid (grid-isolated) modes. In the grid-interconnected mode, the system interacts with the utility grid, contributing or drawing both active power (watts) and reactive power (vars) within its specified power and energy capacities. On the other hand, the microgrid mode enables the system to function autonomously, disconnected from the grid, providing critical power support to the remote community during sustained

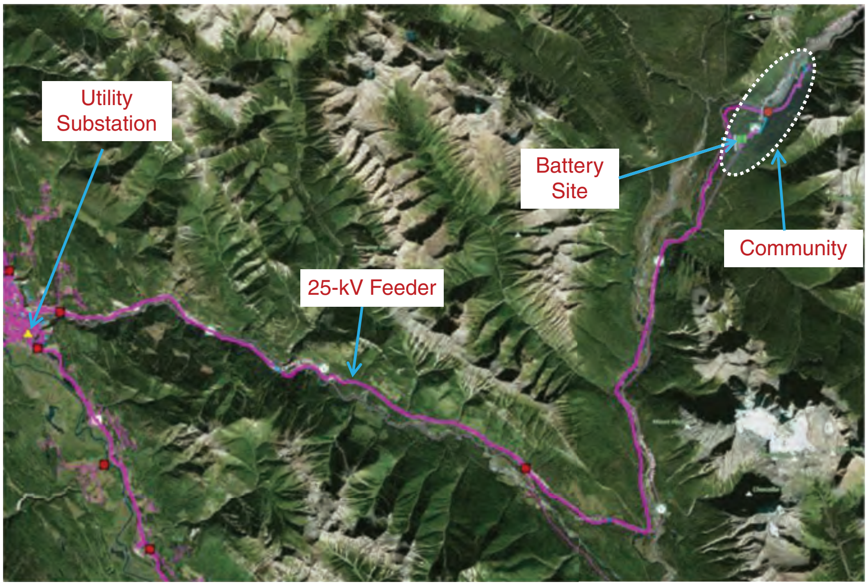


**Figure 2.** The 25-kV feeder geographical layout.

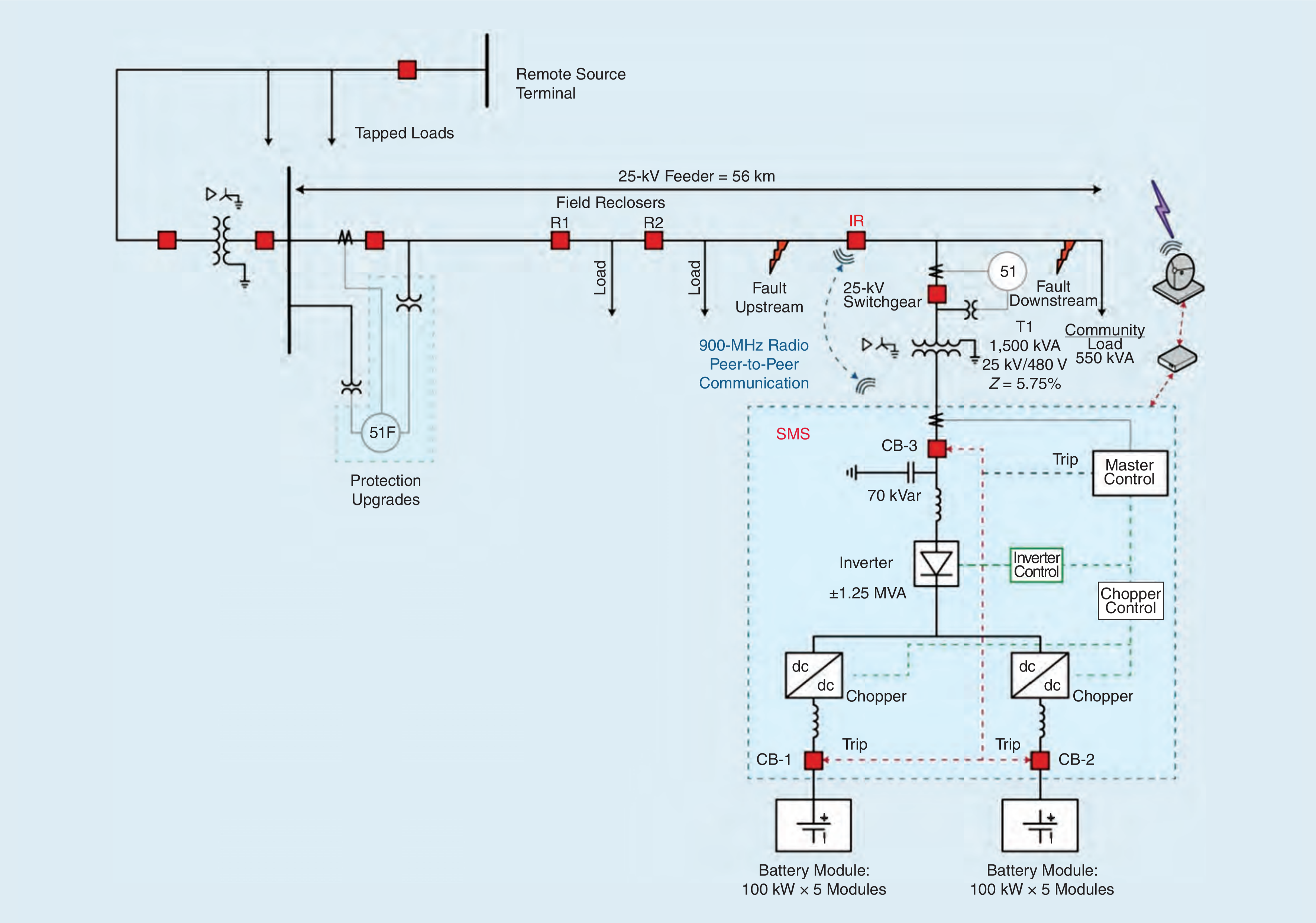


**Figure 3.** The 25-kV feeder one-line diagram. SMS: Smart Storage Management System; IR: fault sensing and interrupter device.

outages. With the ability to engage in four-quadrant power operations, the storage system can efficiently manage active and reactive powers. This flexibility allows it to adapt to grid conditions and consumer demands, ensuring a reliable and responsive energy supply.

The storage system operates in parallel with the 25-kV feeder during regular grid-connected mode. The community load primarily relies on the utility substation, with the SMS operating as a current source using grid-following inverter control. The SMS supplies only balanced or positive sequence load current, contributing to substation load reduction (peak shaving) or charging the batteries post discharge. The SMS does not supply an unbalanced or negative sequence current in this mode.

**Combining energy storage technology with microgrid functionality, this initiative mitigates outage impacts and provides a strategic solution for managing distribution substation demand.**

In microgrid operation, the SMS operates in the voltage source mode or grid-forming inverter control to support single-phase or unbalanced loads. Inverter control is designed to control voltage and frequency instead of limiting unbalanced (negative sequence) current in this mode.

### Transition Between Operational Modes

In the event of permanent faults downstream of the IR intelligent fault interrupter identified by the directional overcurrent condition in the IR followed by auto-reclose attempt failures, load transition to the battery storage system is prohibited. The fault interrupter isolates and allows microgrid mode operation for permanent faults upstream of the IR, between the substation and the IR.

Automatic open-system transition to the microgrid operational mode commences only for permanent faults upstream of the IR. After disconnecting the community supply from the grid due to a permanent fault, the IR initiates load transfer to the storage system when the loss of voltage exceeds the configured time value (30 s). This confirms that the upstream fault is permanent and attempts to restore supply from the station have failed. The IR then isolates the battery storage from the upstream faulted feeder section and signals the SMS to operate in voltage source mode.

Upon identifying the microgrid mode, the SMS undergoes a black start, switching control mode to grid-forming to regulate voltage and frequency, supplying the unbalanced load within the island. The SMS features cold-load pickup and fast voltage/frequency stabilization, ensuring power quality adherence within permissible BC Hydro requirements. The maximum load of the grid-isolated community area is estimated at approximately 550 kVA. At the same time, the storage and SMS system is designed to output up to 1 MW of real power (up to 1.25 MVA apparent power) at regulated voltage and frequency. The energy storage rating of the dc system is 6.5 MWh.

After clearance of the permanent fault and completion of repairs, the system operator restores the feeder from the station. The IR senses the return of utility voltage, initiating a configured time delay, and starts returning to the standard source by signaling the battery to trip off. Subsequently, the IR closes, and community load is reinstated to the standard utility feeder.

### Storage and Microgrid Protection

The SMS plays a pivotal role in ensuring the protection and reliability of the storage and microgrid system. Various protection functions are integrated into the SMS inverter, focusing on the inverter output current for adequate and responsive safeguards. It has built-in protection functions designed to operate on the inverter output current. These functions include the following:

- A fast protection at 480 V with 3,008 A (2 p.u.) pickup swiftly disconnects the storage system on high short circuit currents.
- An inverse-time thermal overcurrent protection with a 1.2-p.u. pickup based on the root-mean-square (RMS) phase current disconnects the storage system in a coordinated manner with a downstream inverse-time overcurrent digital relay (device 51 in Figure 3) on the 25-kV side of the interconnection transformer.

Device 51, located on the 25-kV side of the inverter transformer, provides coordinated protection with the entrance fuses of customers connected to the distribution feeder.

In the microgrid mode, note that the SMS inverter's fast protection can overtrip, i.e., before a large customer fuse responds to some of their in-zone faults. While this introduces a degree of miscoordination, it has been accepted as part of the operational strategy. The inherent tradeoff allows for fast protection, even if it leads to a slight misalignment in high short current fault scenarios.

### Inverter Source Negative Sequence Characteristic

A ground fault creates unbalanced voltages in an electric system powered by conventional positive sequence rotating generators, resulting in high-magnitude negative and zero sequence currents. The phase angles of negative and zero sequence currents lead their voltages by about 90° for a forward ground fault in a conventional system with highly inductive characteristics. The negative sequence current protection became highly popular for ground faults and directionality detections after the arrival of microprocessor relays.

On 27 July 2017, a permanent phase A-C-to-ground fault occurred in the feeder section between the battery system and the community load, i.e., downstream of the IR. Distribution feeder protection and SMS anti-islanding protection correctly deenergized the feeder. As designed, the IR refrained from an automatic transition to microgrid operation due to the permanent downstream fault. However, the system operator attempted manual restoration through the battery system with the IR opened.

The permanent fault was close to device 51. Once the manual restoration was attempted, it tripped, and Figure 4 displays the waveforms captured. The first set of waveforms [Figure 4(a)] shows the phase-to-ground voltages observed. The faulted phases B and C collapsed, and a severe voltage depression was observed in phase A. The second set of waveforms [Figure 4(b)] shows three-phase currents on the 25-kV feeder section supplied by the SMS inverter through the delta-star transformer. The current in the faulted phases was 100 A (RMS) because inverter control limits 3,008 A at 480 V ($\sqrt{3} \times 3{,}008 \times 480/25{,}000$ A = 100 A).

The third set of waveforms [Figure 4(c)] consists of the magnitudes of three sequence component currents. Figure 4(d) illustrates the phasor diagrams of the three sequence components during fault at an instant, shown

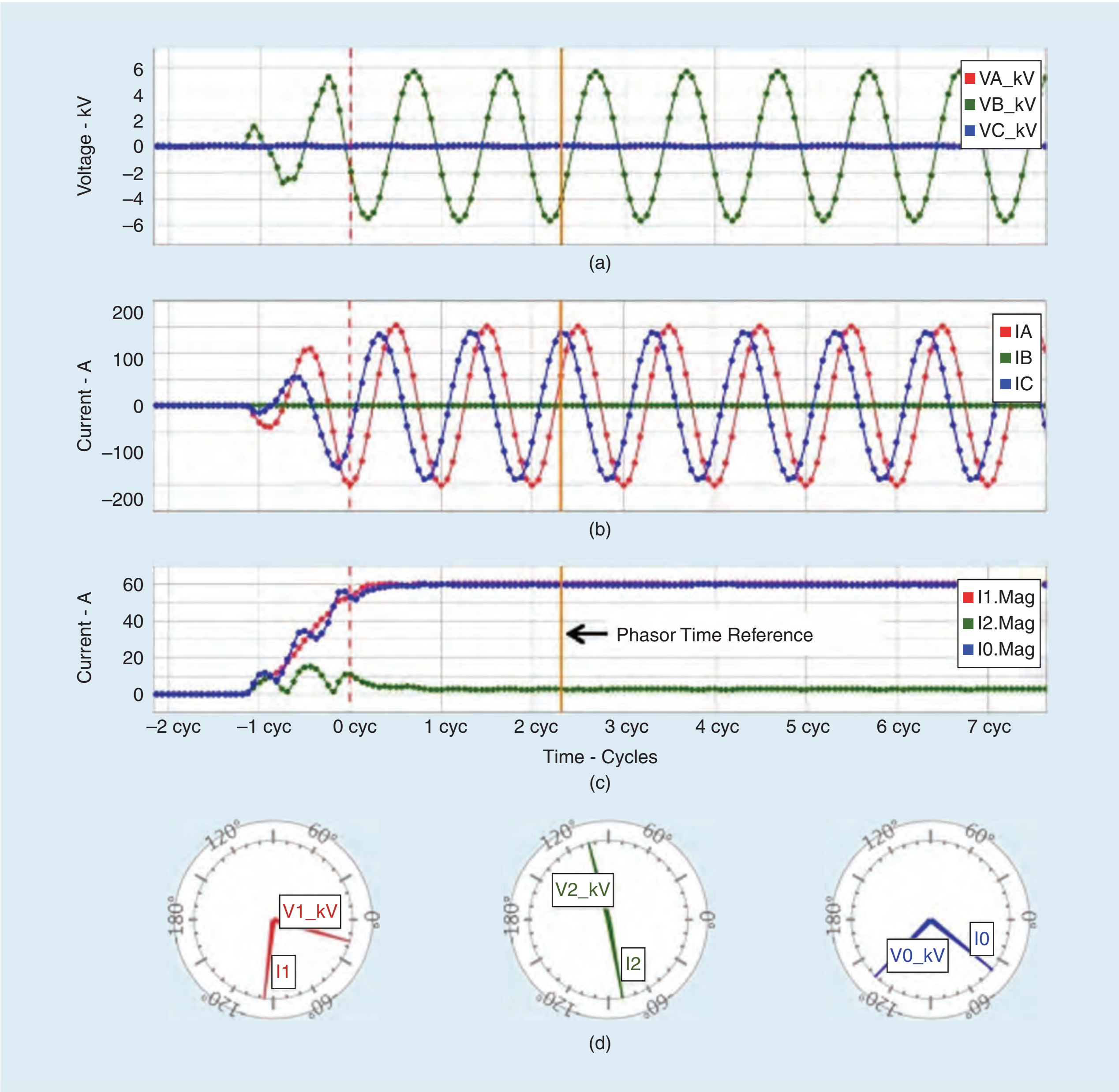


**Figure 4.** Inverter system response to double line-to-ground fault. cyc: cycle.

as "phasor time reference" in the figure. The magnitude of the negative sequence current was too small to be used reliably for ground fault overcurrent protection. The absence of a negative sequence current shows that the inverter source in this application has high negative sequence impedance. Also, the phase angle of the negative sequence current did not lead the voltage by about 90°, indicating that it also can't be used for directionality decisions. However, the zero sequence current had a high magnitude and led the voltage by 90°. The delta-wye grounded transformer provides zero sequence current isolation between the inverter and the system. Because of this isolation, the zero sequence current had a high magnitude and correct phase relationship with the voltage. The recorded fault illustrated that negative sequence relaying, as a fault or directionality detector, is not reliable in microgrids sourced by inverters.

> ***Post implementation, the microgrid system delivered tangible results, notably reducing outage times by approximately 83 h in the first year alone.***

## Conclusions

Integrating DERs brings about a paradigm shift, demanding innovative solutions to the challenges of bidirectional energy flows. Conventional transmission protection solutions, though effective, often prove economically impractical for small-scale renewable resources. The Two-to-One Rule emerges as a cost-effective strategy, optimizing protection upgrades and facilitating the safe connection of small resources to distribution systems. Utilities can harness their potential to shave peak demand, defer costly system upgrades through DERs, and improve the supply reliability of distribution customers by allowing them to function as microgrids after separation.

BC Hydro's successful implementation of a feeder microgrid system is an innovative example, offering a comprehensive approach to enhance reliability in remote communities. Combining energy storage technology with microgrid functionality, this initiative mitigates outage impacts and provides a strategic solution for managing distribution substation demand. As utilities navigate dynamic energy landscapes, the BC Hydro case study is a compelling example of how inventive strategies can concurrently improve reliability and efficiency in power distribution.

Preceding the installation, the community grappled with an average yearly outage duration of 8 h, including prolonged disruptions like the 49.5-h outage in 2013. Access and repair challenges further exacerbated outage durations. Post implementation, the microgrid system delivered tangible results, notably reducing outage times by approximately 83 h in the first year alone.

Microgrid operation emerges as a key driver in enhancing customer supply reliability. The recorded fault incident underscores the limitations of relying on negative sequence relays in microgrids solely supplied by inverter sources. The delta-wye grounded transformer, effectively isolating the generator and the system, ensures the reliable operation of zero sequence protection for the commonly encountered ground faults, irrespective of the source type—whether inverter or conventional.

In summary, the journey through DER integration, microgrid deployment, and protection strategies illuminates the transformative potential of innovative solutions. The BC Hydro case study, with its real-world impact on reliability and efficiency, serves as a guiding light for utilities navigating the complexities of modern power systems. As the energy landscape evolves, strategic and dynamic approaches will remain essential for building resilient and reliable power infrastructures.

## For Further Reading


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