Protection Strategies for Integrating Battery Energy Storage Systems in Transmission Networks

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Abstract: Battery storage is increasingly pivotal in balancing supply and demand in modern power grids. It stores surplus energy generated by solar and wind resources during favorable weather conditions and releases it to cover deficits when conditions are less optimal. A project is underway to integrate a 150 MW/300 MWh battery storage system into a 115 kV transmission network. As a direct current (DC) source, the battery requires an inverter system to connect to the alternating current (AC) grid. Inverter control systems respond to short-circuit faults differently from traditional synchronous generators, presenting challenges to the reliability of existing protection schemes based on the well-understood short-circuit responses of conventional generators. This paper discusses the additional measures incorporated into transmission line protection to enhance reliability without compromising security and ensure compliance with mandatory regulatory standards.

Keywords — Inverter-Based Resource (IBR), Battery Storage, Collector Substation, Line Protection, PRC-024-3 and PRC-025-2

I. INTRODUCTION

The electric power grid is transforming significantly as renewable energy sources like solar and wind quickly replace traditional coal and gas power plants. This shift is driven by the urgent need for cleaner and more sustainable energy. However, renewable resources have a unique challenge: their intermittent nature — solar panels generate electricity only during daylight, and wind turbines produce power only when the wind blows.

Battery storage technology has become crucial to address this intermittency. Batteries store excess electricity generated during periods of high renewable output, ensuring a stable and reliable power supply. This stored energy can then be dispatched to the grid when renewable generation is low, such as on cloudy days, in calm weather, or at nighttime.

This paper explores an ongoing project involving integrating a 150 MW/300 MWh battery storage system into an electric utility grid's 115 kV transmission system. A key component of this integration is an inverter system that converts the battery's DC output into AC suitable for grid use. The paper focuses on the protection engineering challenges associated with this integration, particularly the impact on transmission line protection due to the unique short-circuit current response of the battery's inverter control system.

Unlike conventional synchronous generators, the inverter's control system can regulate short-circuit output currents rapidly — often within a single cycle of a short-circuit event. This quick regulation produces a balanced output shortly after an unbalanced fault, supplying a small and unpredictable negative sequence current. Such short circuit response poses significant challenges for distance and directional protection relays, typically used in transmission line protection [1]. The paper also discusses the countermeasures to address these reliability challenges, particularly during unbalanced faults.

The paper is structured as follows:

Section I introduces the problem and outlines the paper's scope.

Section II uses a generic inverter model within a commercially available steady-state short-circuit simulator to highlight the challenges of controlled short-circuit current responses on transmission line protection.

Section III provides details of the collector station configuration and its protection systems. It describes how the battery is integrated into the 115 kV transmission network with inverters.

Section IV delves into the 115 kV transmission line protection and the countermeasures necessary when the inverter-controlled source is the primary source of short-circuit current.

Section V discusses anti-islanding protection, essential as the battery source cannot operate in isolation with customer loads.

Section VI addresses the NERC (North American Electric Reliability Corporation) regulatory design requirements. While a comprehensive discussion of all regulatory requirements is beyond the scope of this paper, this section focuses on the specific design requirements of two Protection and Control (PRC) standards, PRC-024-3 and PRC-025-2, requiring special attention. NERC has recently approved two additional standards, PRC-028-1 and PRC-029-1, for inverter-connected resources. This paper also does not cover them, as the design enhancements required for compliance are still under development.

Section VII finally summarizes the conclusions of the paper.

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II. Inverter Control and Short-Circuit Characteristics

A power electronic inverter converts the DC output from a Battery Energy Storage System (BESS) into AC. Due to the low thermal time constant and rating of the semiconductor devices used in inverters, the control system must limit the inverter's output current during short circuits. This control system responds swiftly, typically within one power frequency cycle or slightly longer after the inception of a short-circuit. Unless mandated by grid codes, the inverter control maintains a positive sequence or three-phase balanced current output even during unbalanced faults, distinguishing its response from that of traditional synchronous generators.

Traditional synchronous machines produce high-magnitude short-circuit currents that significantly lag the faulted phase's voltage. Their windings provide a low-impedance path, leading to high flows of negative sequence or unbalanced current during unbalanced faults. The short-circuit response of these machines to balanced and unbalanced faults can be universally characterized using machine parameters and is predictable. In contrast, each controlled inverter's short-circuit response is unique, depending on the supplier's algorithm.

A. Grid-Following Control

Most inverters operate in grid-following mode [2], utilizing a phase-locked loop (PLL) that uses a synchronizing signal from the grid. The PLL locks onto the grid voltage, and the control system adjusts the firing of power electronic devices accordingly. The inverter injects current with a phase angle relative to the grid voltage, providing the desired active and reactive power. This type of inverter has built-in protection that automatically stops after disconnection from the grid.

The inverter control for connecting the BESS also operates in grid-following mode, capable of delivering or absorbing positive sequence currents with complete four-quadrant power factor control. The control also limits the short-circuit current to a configurable level between 1.0 pu and 1.2 pu, on the reference 2,706 A at 480 V AC. The control system is designed to ride through voltage excursions in compliance with the NERC standard PRC-024-3.

During low or high system voltages, the control system prioritizes reactive power, supplying or absorbing reactive power to support the grid within the configured short-circuit limit. However, the control system is programmed to minimize unbalanced or negative sequence current flow. Some inverters may supply only positive sequence currents during balanced and unbalanced faults. Other inverters may supply positive and negative sequence currents during unbalanced faults. The negative sequence current supplied can have a different frequency than the voltage, creating unpredictable angular relationships between the negative sequence currents and voltages [3].

B. Short-Circuit Model and Response

The inverter control system is highly complex and often proprietary, and suppliers typically do not share detailed designs. Some suppliers provide a black box model of their control system, which cannot be used in commercially available steady-state short-circuit analysis programs. Instead, detailed Electromagnetic Transient (EMT) simulations are often required to model the short-circuit response of inverter controls. These EMT simulations demand specialized skills and are time-consuming.

Performing detailed EMT simulations to develop protection settings is impractical and uneconomical for projects integrating small or mid-sized inverter-based resources (IBR). Therefore, protection engineers rely on simplified generic IBR models now offered by steady-state circuit programs. Simulations from these programs provide a high-level assessment of an IBR's controlled short-circuit response. Protection engineers use this information to exercise additional caution when developing settings to achieve protection reliability goals.

ETAP, the Electrical Transient Analyzer Program [4], includes a short-circuit simulator module. This module offers a generic IBR model as a voltage-controlled current source that can be used for high-level assessment and development of protection settings. Fig 1 is a screenshot showing the model parameters used. The short-circuit current injection in the model is set to 1.2 pu with reactive current power factor priority and no negative sequence current injection. After two voltage transformations, the model connects the inverter to the grid, using 415V/34.5 kV and 34.5/115 kV transformers. The 34.5 kV/115 kV transformer windings are star-grounded and star-grounded with a buried delta tertiary. Balanced and unbalanced faults were applied on the 115 kV bus.

Figures 2 through 4 illustrate the steady-state responses to these faults using 60-Hz phasors, representing the 115 kV bus voltages and the currents from both the grid and the IBR sides. In the case of unbalanced faults, the phasors are depicted in the ABC system, with their sequence components shown adjacent to them. Notably, the current from the IBR side was significantly lower in magnitude than the grid side; however, the magnitudes have been adjusted in the figures for visual clarity.

Fig 2 is the response to Phase B-to-C fault. The short-circuit current response from the grid is as expected from a traditional synchronous generator; the positive sequence current lags the corresponding voltage by about 90°, while the negative sequence current leads by about the same angle. In contrast, the IBR short-circuit current response comprises only positive sequence currents with a phase angle close to the corresponding voltages, essentially supplying active power. The magnitude of the current from the IBR is limited to 1.2 pu of the total inverter rating.

Fig 3 is the response to Phase A-to-ground fault. The traditional generator's positive sequence current lags the corresponding voltage, while the negative and zero sequence currents lead by about 90°. The IBR's short-circuit current appears different but is like the earlier fault; it consists of a balanced current with a magnitude of 1.2 pu, essentially supplying active power. However, this current is superimposed with a zero-sequence current from the buried delta tertiary winding of the 34.5 kV/115 kV transformer. This makes it appear different from the earlier fault. The zero-sequence current from the delta winding leads the corresponding voltage by about 90°, and protection engineers often refer to this delta winding configuration as a source of zero-sequence current.

In the case of a three-phase fault, shown in Fig 4, both the grid and IBR exhibit positive sequence current injections, lagging pre-fault voltages by about 90°. The voltage on all three phases of the 115 kV bus collapses for this fault. Thus, the pre-

fault voltages, as shown by dotted lines in the figure, are used to illustrate the phase relations. The IBR also supplies current like a traditional generator because its control is set to operate with reactive priority or provide balanced reactive current in response to a balanced voltage drop.

Fig. 1: Screenshot of inverter model parameters

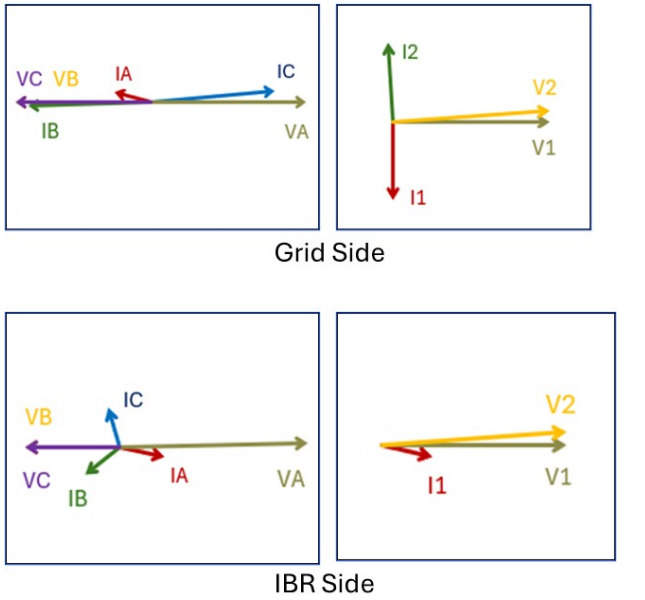

Fig. 2: Current injections from the grid and IBR sides for a Phase B-to-C short circuit fault

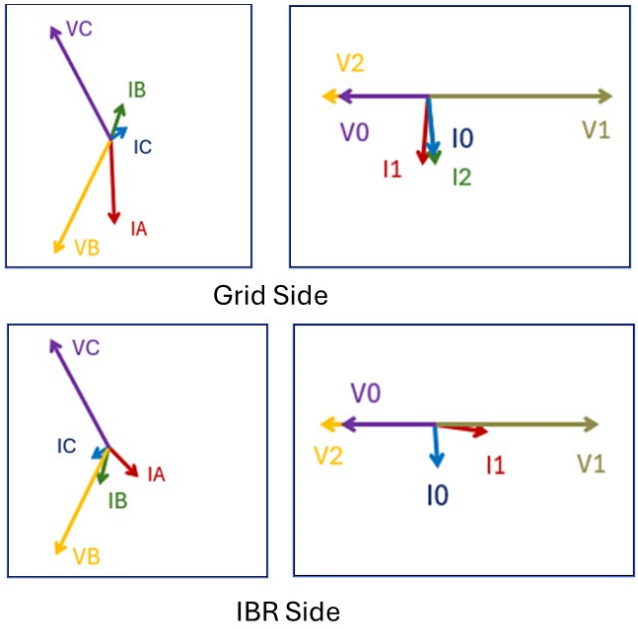

Fig. 3: Current injections from the grid and IBR sides for a Phase A-to-ground short-circuit fault

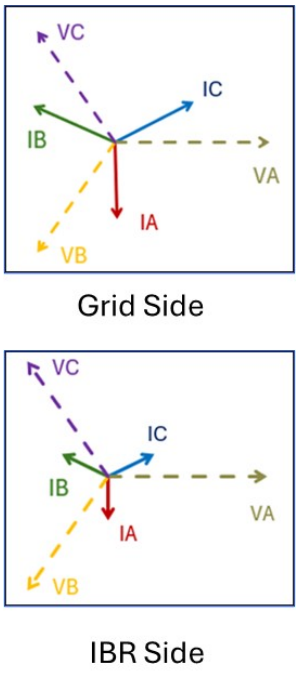

Fig. 4: Current injections from the grid and IBR sides for a balanced three-phase short-circuit fault

C. *Protection Reliability Challenges*

The short-circuit current output from IBR differs markedly from the grid sourced by traditional synchronous generators, particularly during unbalanced faults. Key differences and their negative impact on the reliability of protection operating primarily on IBR current include:

1. **Lack of Reliable Negative Sequence Current:** The inverter control suppresses negative sequence current, allowing mostly balanced or positive sequence current even for unbalanced faults. Some inverter control systems may permit negative sequence current flow during an unbalanced fault, a protection relay can detect that. However, the angular relationship between the negative-sequence current and voltages will be unpredictable [3]. Modern phase distance relays relying on negative sequence directional elements will fail to operate reliably for unbalanced faults, and ground distance relays polarized by negative sequence current will also operate unreliably [5 6].

2. **Non-Homogeneity of Sources:** The phase angles of fault currents supplied by the grid and IBR are significantly different for unbalanced faults. Non-homogeneous phase angles of fault currents from line terminals can restrain line current differential protection from operating on internal faults [7].

3. **Limited Short-Circuit Current:** The minimum current supervises the line distance and directional relays, which will fail to operate when the short-circuit current, limited to 1.2 pu, is below the supervising current.

Subsequent sections discuss countermeasures undertaken to mitigate the reliability risk integration of BESS and its associated inverters.

III. Collector Station Configuration

Fig. 5 illustrates a 115 kV regional transmission network with a BESS connection. Two transmission substations, designated as B and C, have 115 kV station buses connected to the integrated utility network. Station A, a switching station, features three 115 kV transmission lines labelled Line α, Line β, and Line γ. The remote terminals of the two lines terminate at Substations B and C, while the third line connects to Substation D, where the 115 kV bus also serves as the point of interconnection (POI) for the BESS.

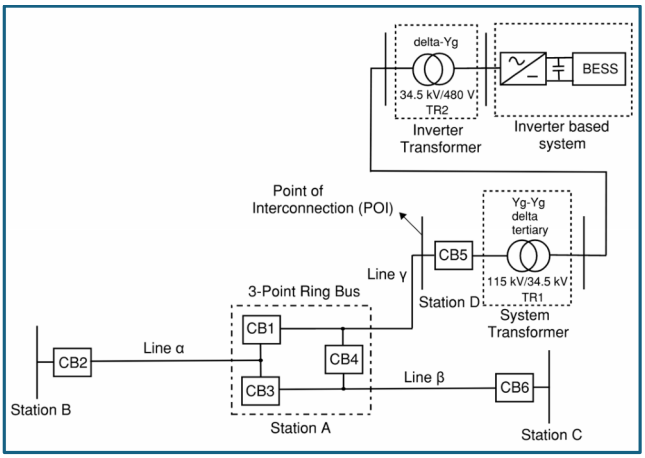

Fig. 5: Schematic of 115 kV transmission network integrated with BESS

A. *Battery Pack and Inverter*

The BESS at this facility comprises 82 Li-ion Tesla Megapack 2XL PBEs, each rated for 3,854 kWh of stored energy at the beginning of life (BOL). The modular inverters collectively provide a rated output of 2.25 MVA at 480 V AC. As discussed, the inverter control operates in grid-following mode with four-quadrant power factor control and automatically stops the inverter upon disconnection from the grid. The entire BESS facility rating is 150 MW/300 MWh, whereas the inverter system capability is 184.5 MVA continuous.

The inverter control limits the short-circuit current to a configurable level between 1.0 pu and 1.2 pu, based on a pre-fault reference rating of 2,706 A from a battery pack and inverter at 480 V AC. For this project, a limit of 1.2 pu is selected. On a short-circuit fault in the AC system accompanied by a significant voltage sag, the inverter current increases to 3,247 A and reverts to 2,706 A after a delay.

Each inverter has a 3,000 A at 480 V power circuit breaker and an integrated electronic trip unit (ETU). The ETU operates on current from the grid and opens the circuit breaker when the inverter experiences short-circuit faults. The factory default trip settings coordinate with the upstream fuse and the overcurrent relay pickup on the inverter transformer's high side (34.5 kV), as discussed in the following subsection.

B. *Inverter Transformer*

A pair of battery packs and dedicated inverters connect to a 4,500 kVA 480 V/34.5 kV pad-mounted transformer with a nameplate impedance of 8%. The 34.5 kV windings are

connected in delta, whereas the 480 V windings are in a wye configuration with the neutral solidly grounded. Eight or nine inverter transformers are loop-connected by 34.5 kV cables, forming five collector feeders.

The 34.5 kV transformer bushing is connected to a 102 A weak link fuse with a curve shape selected by the manufacturer for coordination with the current limiting fuse. The transformer also has two 200 A current-limiting fuses in parallel, in series with the weak link fuse, protecting against the full range of available short-circuit currents from the grid. The weak link fuse offers primary protection for the pad-mounted 480 V/34.5 kV transformer, operating on high impedance faults. The current-limiting fuse quickly isolates the transformer during high short-circuit currents on the 34.5 kV windings, limiting let-through current and minimizing potential damage from increased short-circuit levels from the grid.

An inverse-time element is implemented in a multi-function microprocessor-based relay connected to the 34.5 kV transformer bushing CTs, with a pickup setting more sensitive than the transformer fuse for overload protection. The relay provides two levels of instantaneous protection to reduce the available incident energy from the 34.5 kV grid supply during short circuits in the inverter to support maintenance activities. In addition to tripping the local 480 V circuit breakers, the relay is configured to send a Direct Transfer Trip (DTT) signal to open the upstream collector feeder breaker. The DTT is not externally enabled in maintenance mode. Utilizing a maintenance mode would have avoided the miscoordination between the high-speed sensitive relay elements and the transformer fuses, however, the facility owner desired the element always to remain active to prioritize safety.

However, this sensitive overcurrent protection presents a risk of false operation caused by high inrush current during transformer energization from the 34.5 kV supply source. To mitigate this, security during transformer energization is ensured through torque control and 2nd harmonic blocking, coordinated with the feeder breaker status. Since the relay protection is set more sensitively than the fuse, it will operate before the fuse begins to melt in the event of an inverter short circuit, with the fuses serving as backup protection.

The delta/wye transformer, with 480 V wye winding solidly grounded, provides a stable reference point for the three AC voltages from the inverter. Since the inverter neutral is not grounded, the transformer is the sole zero-sequence current source for ground faults in the inverter. The delta winding on the 34.5 kV results in the 34.5 kV collector system having only one grounding point at the neutral of the 34.5 kV/115 kV interconnecting transformer. The advantage of having an ungrounded delta winding is that it provides a barrier to zero-sequence currents and some harmonic frequencies (triplets) passing between the inverter and the 34.5 kV collection system.

C. Collector Feeder

Fig 6 illustrates a partial single-line diagram of one of the five collector feeders, showing three of the eight (or nine) inverter transformers connected in a loop configuration. Each feeder can consist of up to two such “strings.” The collector feeders are protected by inverse-time phase and ground overcurrent protection, coordinated with downstream 34.5 kV fuses at the inverter transformers.

Due to the 34.5 kV delta winding of the inverter transformers, the inverters do not supply zero-sequence current during 34.5 kV ground faults. In the event of a ground fault on the 34.5 kV collector feeder cable, the feeder ground overcurrent protection, embedded in Device 51F shown in Fig 7, at the collector bus operates based on the zero-sequence current from the 34.5 kV supply source (grid), disconnecting this source. However, standard practice often involves relying on automatic shutdown to disconnect the inverter source after the 34.5 kV supply source (grid) disconnection. This practice can result in a temporary voltage rise on the healthy phases of the cable during the interval between the grid disconnection and the inverter shutdown. The voltage can be elevated to line-to-line or even higher, depending on the cable's charging current [8]. A detailed EMT analysis is recommended to assess this risk.

This application significantly reduces risk by incorporating a DTT from the feeder protection to the inverter breakers. When the feeder protection trips its 34.5 kV breaker, it simultaneously sends transfer trips to open the 480 V breakers of all inverters connected to that feeder. This direct tripping method ensures the near-simultaneous disconnection of the 34.5 kV supply and the inverters, minimizing the exposure of healthy phases to elevated voltages. The exchange of DTTs between the feeder protection and the sensitive overcurrent relays (provided to reduce incident energy) is carefully designed to prevent channel lockup or a "ping-pong" effect.

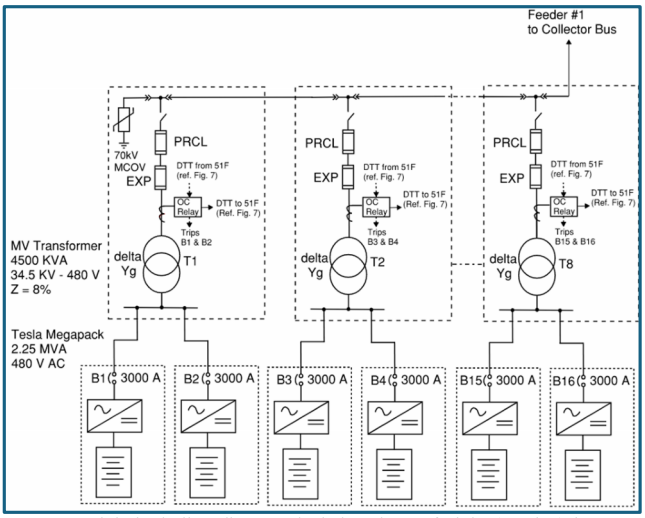

Fig. 6: Partial single-line diagram depicting three of eight (or nine) inverter transformers loop connected to form one half of Collector Feeder #1

D. Collector Bus and Interconnecting Transformer

All collector feeders eventually terminate at a single 34.5 kV collector bus, tying together all inverter transformers. Fig. 7 illustrates a simplified one-line diagram of the collector bus and the interconnecting transformer. The collector bus interconnects to the utility POI through a 34.5/115 kV interconnecting transformer, rated 105/140/175 MVA with a nameplate impedance of 9% at 105 MVA. Both windings of the transformer have star configuration and are solid grounded. The transformer also includes a buried tertiary delta winding, serving as a zero-sequence current source for ground faults on either side

of the transformer and providing effective grounding to both sides.

The collector bus is equipped with inverse-time phase and ground overcurrent protections, coordinating with the downstream overcurrent protection on the collector feeder. The interconnecting transformer is provided with dual differential and restricted earth fault protections.

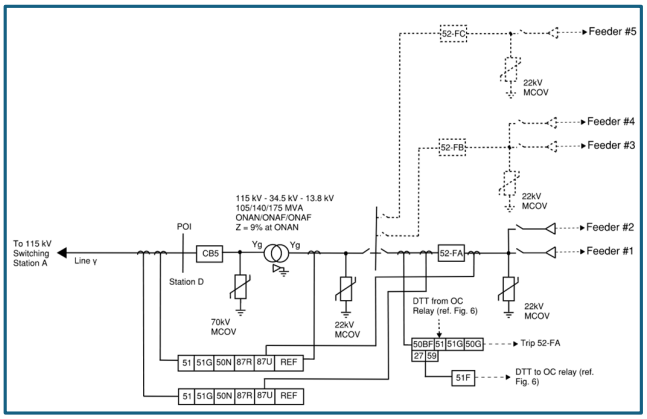

Fig. 7: Single-line diagram of the collector Station, showing relaying for only two of the five feeders

E. Inverter Shutdown and Reconnection

The 34 kV fuses, overcurrent protection, and ETU are not sensitive enough to respond to the short-circuit current output from the inverter(s). In the event of a fault on the collector feeder, the feeder protection will trip the local breaker, disconnecting the 34.5 kV supply source and sending DTT to open the 480 V inverter breakers. Should any 480 V breaker fail to open, the disconnection of the 34.5 kV supply causes the PLL in the inverter control to lose its synchronizing source, initiating an automatic inverter shutdown and taking it offline. The inverter cannot be returned online until the collector feeder and the inverter transformers are reenergized from the 34.5 kV supply source.

IV. Transmission Line Protection

The utility regional system shown in Fig 5 includes lines designated as Line α, Line β, and Line γ. The integration of the BESS system challenges the reliability of the line protection system [9]. Line γ connects BESS to the grid, with one terminal supplied by inverter sources converting BESS DC to AC voltage. These resources are commonly referred to as Inverter-Based Resources or IBR. During N-1 contingencies, Lines α and β can also be solely supplied by IBR when one of them is out of service. This section discusses the protection system employed on these lines and the measures taken to ensure protection reliability when IBR is the sole source at one terminal.

A. Line γ Protection

Line γ is a short line with one terminal connected to the utility grid at Station A and the other to IBR at Station D. The line protection consists of fully redundant, modern current differential protection. This section briefly discusses the primary line current differential protection and countermeasures for backup protection.

Primary Line Current Differential Protection

Current differential protection operates on Kirchhoff's law and is considered the most reliable. In a line current differential scheme, analog signals between the line terminals are exchanged over wideband tele-protection channels. Unequal propagation delays between the transmit and receive channels through the communication routers require additional security measures to prevent incorrect operation for external faults on adjacent lines.

The line current differential protection in this application employs the α-plane characteristic of Kirchhoff's current law, offering improved performance over the percentage-bias characteristic when guarding against incorrect operations during external faults, as shown in Fig 8. In this figure, I_{local} and I_{remote} are the 60-Hz phasors from line current measurements taken at the local and remote terminals, respectively. The dotted circle in the diagram—an approximate cardioid—illustrates the mapping of a percentage slope characteristic on the α-plane. This characteristic has a slope of 0.7 with the restraining current defined as $|I_{local}| + |I_{remote}|$ [10].

Table 1 lists the relay supplier's recommendations for the α-plane characteristic on a traditional line supplied by conventional generators on both terminals [7]. The region hatched by horizontal red lines shows the large restraint region in the α-plane, illustrating inherent bias toward line protection security.

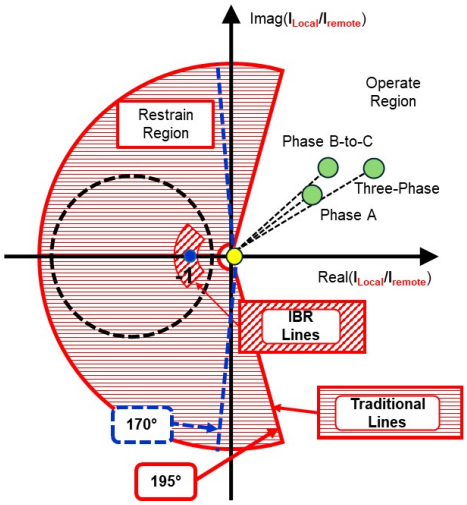

Fig. 8: The α-plane characteristic

Table 1: Recommendations from line current relay supplier

Settings	Traditional Lines		IBR Lines	
	Phase	Ground	Phase	Ground
Pick up	1.20 pu	0.25 pu	0.30 pu	0.20 pu
Radius	6	6	1.35	1.35
Angle	195°	195°	90°	90°

Although highly reliable, differential protection can sometimes fail to operate on an internal fault in a line interconnecting IBR to the grid with a weak source. Thus, the relay supplier recently provided new recommendations for lines supplied by IBRs. Table 1 includes these recommendations and crossed-hatched red lines illustrate the associated restraint region in Fig 8. The supplier's recommendation entails a significantly smaller restraint region, suggesting the use of highly sensitive settings to accommodate low magnitudes of fault currents from the weak grid and IBR, and the non-homogeneity of their phase angles (the short-circuit current from the grid having the phase angle lagging the voltages by about 90° whereas from the IBR, it can be significantly less than 90° or even close to 0°).

This application's line terminal at Station A is connected to a stiff grid source. The three-phase short-circuit strength at Station A, excluding contributions from IBR or when Line γ is out-of-service, is approximately 7,000 MVA. The grid's short-circuit strength ratio to the IBR is about 30 (7,000/1.2 × 184.5), indicating that the short-circuit current from the grid at Station A is significantly higher than that from the IBR at Station D. Given the substantially stiff grid source at one terminal, traditional line protection settings are chosen. The grid's ability to deliver high current during short circuits reduces concerns about the low magnitude and differing phase angle of the IBR's short-circuit current. Traditional line current differential protection settings with only the following minor adjustments are applied:

- The line is short, with a direct fiber link between relay communication ports, eliminating unequal signal propagation delays. As a result, the phase angle setting is reduced from 195° to 170°, enhancing the operating region and protection dependability.
- Sensitive zero sequence and negative sequence differential protection are available in the relay, but only zero sequence protection is used at both terminals.

Using simulation results reported in Figs 2 to 4, the short-circuit currents from the grid and IBR during line internal faults are depicted on the α-plane characteristic in Fig 8. The green dots are measurements by the differential relay at Station A for the three faults: three-phase, two-phase and single-phase faults. At Station D, all three measurements are close to each other near the origin of the α-plane characteristic because the short-circuit current from the IBR is minimal compared to the grid. Thus, the ratios of I_{local} to I_{remote} are small fraction numbers shown by a single yellow dot at the origin. All dots are in the "Operate Region," confirming the dependability of the applied line current differential protection.

Communication-Independent Phase Distance Protection

The current line differential protection must have a backup independent of tele-protection channels. Modern multi-function line current differential relays include backup step distance protection. The reliability of distance protection is typically at risk on lines supplied solely by IBR due to the following reasons:

1. **High Source Impedance:** IBR introduces high source impedance by limiting short-circuit current output to typically less than 1.5 pu—1.2 pu in this application. This can cause high-speed distance protection (Zone 1) to overreach and incorrectly trip external faults [11]. Therefore, Zone 1 distance protection is typically not applied to lines supplied by IBRs.
2. **Reliance on Pre-fault Memory:** Distance relays depend on pre-fault voltage memory to operate correctly on faults close to the relay location [9]. The underlying assumptions of memory-polarized relays include:
   - The phase angle of the source voltage behind the relay remains unchanged from the pre- to post-fault state within the relay's operation timeframe.
   - The short-circuit current has an inductive characteristic, with its phase significantly lagging the faulted phase voltage.

   While these assumptions hold for high-inertia traditional generators, an IBR with grid-following control has no inertia. The phase angles in the pre- and post-fault states are not the same. In addition, depending on the IBR control system, the short-circuit current may not lag the voltage.
3. **Lack of Reliable Negative Sequence Current:** The relay used in this application supervises the operation of the distance protection with a negative sequence directional element for unbalanced faults. It will not operate as expected because the inverter control suppresses the negative sequence current supply [3 5 6].

Despite these limitations, the industry continues to apply distance relays with some countermeasures for lines with IBRs due to a lack of reliable alternatives.

Only Zone 2 overreaching phase distance protections are employed as backup at both terminals, with a 20-cycle time delay in this application. However, due to the abovementioned limitations, Zone 2 is unlikely to operate at the IBR terminal on any fault. Again, Zone 1 is not applied at both ends due to the limitations discussed and the short line.

Supplemental Phase Undervoltage

The Zone 2 backup distance protection at Station D is unlikely to operate on a phase fault when line current differential protection is not working due to tele-protection failure concurrent with an internal line fault. Therefore, the Zone 2 phase distance can be supplemented with phase-to-phase under-voltage protection at that terminal, using multiple definite-time elements. Under-voltage protection is non-selective and thus must be set with a long delay to allow the protection systems on the adjacent lines to operate first for their faults. Its pickup and time delay must also not interfere with mandatory low-voltage ride-through requirements. Fig 9 illustrates how this under-voltage protection is coordinated with the low-voltage ride-through requirements mandated by the NERC PRC-024-3 Standard [12]. This application uses only a single under-voltage element with 0.3 pu pickup and a 5-second delay. This 5-second delay is used because a low-voltage-ride requirement does not apply after 4 seconds.

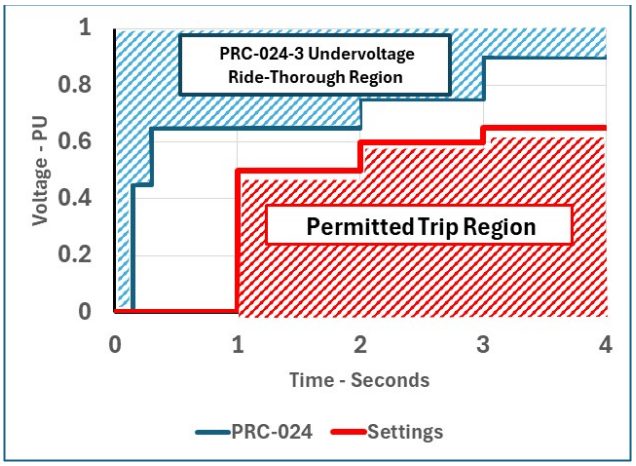

Fig. 9: Supplemental phase undervoltage protection and its compliance with PRC-024-3

Phase Fault Clearing Times

So long as the current differential protection is available, all faults on the line will be cleared immediately. The current differential protection becomes unavailable in an unlikely contingency involving the loss of redundant tele-protection channels, and a line fault occurs (N-2 contingency and a line fault). Zone 2 will clear a phase fault from the grid at Station A with a 20-cycle added delay. However, the clearing time at Station D, the IBR terminal, can take up to 5 seconds by the under-voltage protection or even sooner by the automatic shutdown of the inverter upon disconnection from the grid. After the Zone 2 protection operates at Station A and isolates the line from the grid, the 5-second fault clearing time at Station D does not pose an additional risk to system stability and power quality.

Zero Sequence Directional Overcurrent

Ground fault backup protection is provided using zero sequence directional overcurrent. Although IBR does not supply zero sequence current, the buried delta tertiary winding of the 34.5/115 kV interconnecting transformer, which interconnects the collector station to the line, acts as a zero-sequence current source, as long as the line remains connected to the grid through Station A. This ensures that zero sequence directional overcurrent protection will work reliably at Station D, even with IBR being the sole source at that station. If the line becomes isolated from the grid, under-voltage protection or automatic shutdown will disconnect or de-energize the ground fault.

B. Line β Protection

Line β is connected to two substations, Stations A and B. The line protection system consists of the following:

- a line current differential protection
- directional comparison blocking (DCB) scheme

So long as Line α is in service, Line β line is predominantly supplied by the grid, powered by traditional generations. Under an N-1 contingency comprising Line α out-of-service, Line β will be supplied IBR connected at Station A, risking the line protection reliability without countermeasures. This section discusses these countermeasures to mitigate the risk.

Primary Line Current Differential Protection

Line β's current differential protection is configured similarly to Line γ, except adding the negative sequence differential protection element. Occasionally, when Line α is out of service, and an IBR is the sole supply source, the IBR control is expected to provide the negative sequence current values that are unreliable for the line protection. Thus, it was decided to inhibit the negative sequence differential element when IBR is the sole source and an unbalanced fault occurs. To inhibit, the negative sequence current differential pickup is set above the maximum possible short-circuit current output from the IBR, calculated using the following formula [13]:

$$I_{2pickup} = 1.25 \frac{1.2 \times 185{,}000}{\sqrt{3} \times 115 \times 600 \times 5} \quad \text{or } 0.5 \text{ pu} \qquad (1)$$

In the equation above:

- 1.2 pu is the maximum short-circuit current of the rated inverter output,
- 1.25 is the safety margin,
- 0.5 pu is the negative sequence current differential pickup, $I_{2pickup}$, referenced to the 5 A rated CT output,
- CT ratio is 600 or 3000:5.

The selected negative sequence current differential pickup at both terminals of Line β will dynamically inhibit this element when the IBR is the only source at one terminal after Line α becomes unavailable. The phase and zero sequence differential protection will continue to provide reliable protection during this contingency.

Directional Comparison Blocking Protection

Directional comparison blocking (DCB) is a communication-assisted scheme that provides selective and high-speed line protection by utilizing overreaching fault detectors combined with directionality detectors [14]. The scheme requires only a single-bit data exchange between the relays at the line terminals, making it suitable for transmission lines with limited channel bandwidth.

The DCB scheme is inherently biased towards dependability over security. For instance, in the case of an external fault (F1) outside the Line β protection zone in Fig 10, the fault and directionality detectors at Station C detect it as a forward fault but wait for two cycles to hear from the relay at Station A. Simultaneously, the relay detectors at Station A detect this fault as a reverse fault and transmit a blocking signal to the relay at Station C, preventing it from tripping for the external fault. Suppose the blocking signal does not arrive at Station C within the two-cycle wait time due to communication channel failure. In that case, the relay at that station will trip for an external fault, prioritizing dependability. For an internal fault (F2) within the Line β protection zone, detectors in the relays at both line terminals identify this fault as internal and do not send the blocking signal to each other, tripping both relays after a wait time to disconnect the line.

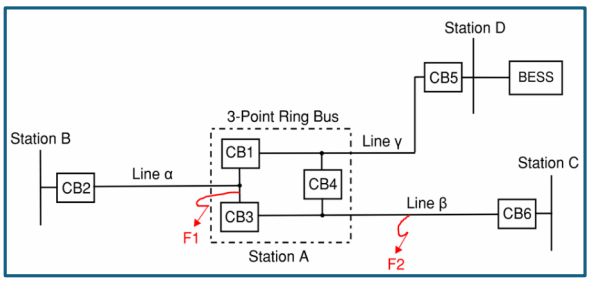

Fig. 10: Fault analysis with the conventional sources at both ends of Line β

While the DCB has proven reliable for decades, this application applies an additional countermeasure to combat the risk for Line α contingency when IBR is the sole source at Station A. The countermeasure is necessary because this DCB scheme uses positive sequence memory polarized phase distance elements as phase fault detectors, and ground distance and zero sequence overcurrent elements as ground fault detectors. The directionality detectors use negative sequence polarized quantities.

During a Line α contingency, there is no risk to the DCB scheme for an external fault (F3) shown in Fig 11, as it operates at both terminals on the short-circuit current from the traditional sources within the grid. For an internal fault (F4), the short-circuit current at Station A is only from the IBR, with no or unpredictable negative sequence current. The fault and directionality detectors at that terminal are set using equation (1), preventing their operation However, the relay at Station C will still trip correctly due to:

- The detectors at Station C operate on short-circuit current from the grid.
- The detectors at Station A are set to restrain, preventing the relay from sending a block signal.

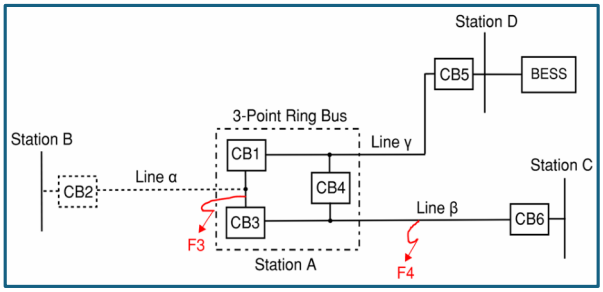

Fig. 11: Fault analysis with IBR at one end of the line β

Therefore, the inherent dependability bias built into the DCB allows the line protection to trip correctly for an internal fault. A countermeasure is necessary to disconnect the line at Station A because the relay at that terminal may fail to operate. This countermeasure includes a DTT from Station C to Station A, requiring one extra data bit to exchange. Transmitting two data bits instead of a single bit is feasible in this application due to the availability of a broadband communication channel between the relays.

Zero Versus Negative Sequence Polarization

A reliable polarized signal is essential for the operation of directionality detectors. The relay used in this application offers directionality detectors that can use either the negative sequence, the zero sequence, or both as the polarizing signal. As discussed earlier, the zero sequence current during short circuits is primarily independent of IBR characteristics because of the delta tertiary winding of the transformer interconnecting the IBR. In contrast, the negative sequence injection is either limited or unknown when the IBR is the sole source during unbalanced faults. An incorrect negative sequence polarized ground distance relay operation was reported in reference [5, 6]. Despite the perceived risk from IBR during Line α contingency, negative sequence polarization is selected in this application.

Fig 12 shows that Line β is mutually coupled with a neighboring transmission line. The zero sequence directional fault detectors are known to operate incorrectly, declaring a forward fault from both line terminals, on the circulating current induced by an external fault on the mutually coupled neighboring transmission line. This risk of incorrect operation by zero sequence polarized directionality detectors persists with or without Line α contingency. In contrast, the risk of incorrect operation only arises from the negative sequence polarized detectors during Line α contingency. A directionality detector is always supervised by overcurrent pickup. In this application, the pickup is set using Equation 1, inhibiting the negative sequence polarized directionality detector during Line α contingency and relying upon DTT from Station C to Station A to disconnect Line β for internal faults during Line α contingency, as discussed earlier.

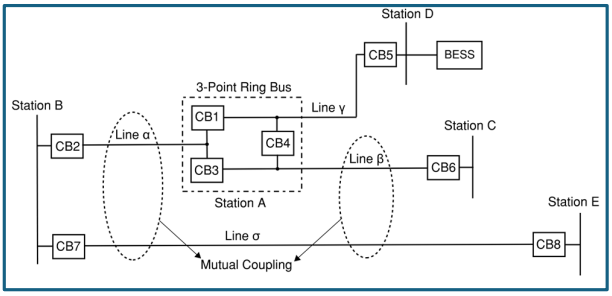

Fig. 12: Transmission lines mutually coupled with neighboring line

Communication-Independent Backup Protection

It is a standard practice always to have line protection relying upon local measurements, ensuring that short-circuit faults in the line are always isolated, irrespective of the status of the communication channel. While line protection using communication telecom channels provides high-speed and highly selective fault clearing, protection relying on local measurements serves as a backup. It can be set to operate at the expense of speed and selectivity. In this application, the following backup protection systems operating on local measurements are applied:

- Phase distance supervised by negative sequence directional detector.
- Ground phase distance polarized by negative sequence current.
- Zero sequence overcurrent toque controlled by the negative sequence directional detector.

- Similar to Line γ, multiple-step phase-phase undervoltage protection at Station A. During a rare N-3 contingency when redundant tele-protection channels and Line α are unavailable, this slow and non-selective protection will be exercised for a line fault.

The negative directional detector supervision current is the same as discussed earlier, above the short-circuit current from IBR.

C. Line α Protection

Line α is equipped with dual current differential protection. It is predominantly sourced by traditional generators embedded in the grid, but IBR solely sources it at Station A during a Line β contingency. It is also mutually coupled. The countermeasures for the line current differential protection and backup protection relying on local measurements are like those discussed for Line β.

V. Anti-Islanding

Islanding the transmission network with BESS is not permitted due to the risk of exposing customers to unsafe voltage and frequency excursions. Additionally, the inverter control limits the short-circuit output to 1.2 pu, which might become inadequate for local protection to detect and isolate faults during contingencies when IBR is the only fault contributor. An active transmission island is hazardous, posing electrocution risks to maintenance crews and the public. It also impedes utility supply restoration by hindering auto-reclose after temporary faults.

The inverter used in the application is designed to operate continuously with grid-following control. Upon losing the synchronizing signal, it is expected to shut down automatically within a few cycles, preventing unintentional islanding with BESS. Besides other shutdown controls, inverters typically include anti-islanding protection, guarding against unintentional islanding from unanticipated contingencies in the transmission system.

The IEEE-2800 standard does not recommend active islanding detection techniques but favors communication-based direct transfer trips. Two layers of passive anti-islanding protections are provided, utilizing voltage and frequency elements. The first layer elements are embedded in the multifunction overcurrent relay of each collector feeder, and the second layer elements are embedded in each inverter control system. The voltage and frequency element settings must coordinate and not interfere with the NERC ride-through requirements stipulated in the PRC-024-3 standard.

VI. Regulatory Requirements

The NERC reference document [15] outlines the bulk electric system (BES) facilities subject to mandatory regulatory requirements. The Battery Energy Storage System (BESS) facility, capable of injecting 184.5 MVA into the 115 kV utility transmission network, qualifies as a BES facility per the NERC guidelines. Consequently, various mandatory NERC standards apply. However, this discussion focuses on the specific requirements of PRC-024-3 and PRC-025-2, given the critical attention needed to comply with these standards.

A. PRC-024-3 Frequency and Voltage Protection Relay Settings for Generators

The voltage and frequency trip relays used in the integration must operate outside the "No Trip Zone," as defined by the standard's ride-through requirements, at the Point of Interconnection (POI). While frequency at the POI or within the collector system is uniform, making it straightforward to develop compliant frequency trip setpoints and delays, voltage measurements present more complexity. Due to load flow and transformer tap positions, the per-unit voltage at the 115 kV bus at the POI can differ from measurements taken within the collector system. This discrepancy complicates determining compliant voltage settings, mainly when applied at levels other than 115 kV or locations other than the POI.

The 115 kV line is equipped with under-voltage backup protection at Station A. As shown in Fig 9, the selected set is carefully designed to avoid interfering with mandatory low-voltage ride-through requirements.

The 34.5 kV collector feeder protection and inverter control include anti-islanding protection, which consists of voltage and frequency elements. These elements must also meet the standard's requirements and be configured to avoid disconnection within permissible voltage and frequency excursions. Voltage setpoints must be converted from 34.5 kV and 480 V to 115 kV at the POI, accounting for worst-case power flow scenarios and transformer tap positions. Although the NERC application guide for this standard [16] provides a methodology for converting voltage setpoints based on an offline tap changer, the interconnecting 34.5 kV/115 kV transformer used in this application is equipped with an online tap changer. At the time of writing, the issue of accommodating an online tap changer in voltage setting calculations remains unresolved. The team is considering using a load flow program to develop compliant voltage element settings that coordinate with the backup under-voltage protection.

B. PRC-025-2 Generator Relay Loadability

This standard sets criteria for protection relay settings associated with generation facility equipment to prevent unnecessary tripping during heavy load conditions and other disturbances that do not threaten equipment protection [17]. However, the standard is primarily designed for large synchronous generators. Adapting and interpreting the standard for distributed generation systems, such as BESS facilities, requires evaluating load-responsive protection elements at each level using the inverter control system's full-load current limit and the combined output of the connected inverters at the relay location.

Full-Load Current Limit:

Unlike traditional synchronous generators, the inverter control in this application limits the full-load current to 2,706 A at 480 V. This limit is not instantaneous; the control system allows the inverter to supply 3,247 A or 1.2 pu short-circuit current for a limited time before reverting to the full-load

current limit after a time delay. This full-load current limit applies regardless of the operating voltage. Therefore, load-responsive protection elements are evaluated against the 2,706 A per inverter output, ensuring this limit is not exceeded, irrespective of operating power factor, efficiency, or voltage depression.

Load-Responsive Protection

The Electronic Trip Unit (ETU) is integrated into the 3,000 A circuit breaker at each inverter output, having a full-load limit of 2,706 A at 480 V. ETU features inverse-time characteristics with a 3000A pickup. Two inverters are connected to one pad-mounted 480 V/34.5 kV inverter transformer, representing a 2×2,706 A full-load capability. A 102 A weak link fuse protects the transformer at 34.5 kV. The weak link fuse is not designed to operate even on the short-circuit current from the inverters, ensuring compliance with Option 5b requirements of the standard. The ETU would operate for the short circuit current but is supplied by the inverter manufacturer as part of the listed system and does not limit the inverter's capability. Additionally, the transformer is equipped with phase overcurrent protection, limiting incident energy from the grid and protecting personnel from an arcing fault on the 480 V bus. The pickup setting used for incident energy reduction also complies with Option 5b.

The 34.5 kV collector bus phase overcurrent protection is evaluated for Option 5b based on the full-load current limit from all 82 inverters. In contrast, the 34.5 kV collector feeder phase overcurrent protection is based on the full-load current limit of loop-connected pad-mounted transformers, each connected to two inverters.

The protection of Line γ uses load-sensitive backup protection, specifically phase distance protection (Zone 2), with reach settings that comply with Option 4 of the standard.

VII. CONCLUSION

The battery storage system is poised to become a critical component in ensuring grid stability as the penetration of intermittent renewable resources increases. However, their integration presents unique protection and reliability challenges that require targeted solutions. This paper examined an 184.5 MVA battery storage system, highlighting and proposing methods to address these challenges.

Most inverters, including the one utilized in this project, are grid-following and automatically shut down when disconnected. Traditional fuses and overcurrent protection devices in the collector substation cannot operate effectively on the limited short-circuit current from inverter-controlled resources. However, they are meticulously selected to ensure reliable operation and isolation of short circuits from the grid within the collector system. It is standard industry practice to rely upon inverters' control to shut down and cease short-circuit current upon grid disconnection. However, direct transfer trips from collector feeder protection to open inverter breakers are implemented to avoid temporary over-voltage on the collector cables after ground faults.

Despite automatic shutdown, utility engineers must implement reliable transmission protection systems even when the inverter is the sole source of short-circuit current to the transmission line. The short-circuit response of an inverter, dictated by its control system, is complex to model and often needs more detailed proprietary information from suppliers. Conducting comprehensive model studies for small to mid-sized installations is typically impractical and economically prohibitive. This paper demonstrated that steady-state short-circuit simulations using a generic model derived from high-level control system parameters can yield critical insights and aid in devising effective protective measures.

The battery in this case study is integrated into a stiff grid, ensuring the reliability of communication-assisted protection systems, provided the communication channels remain intact. Inverters tend to suppress negative sequence currents during unbalanced short circuits, preventing line distance relays' operation. Thus, they are unlikely to operate on the line interconnecting the inverter to the grid and other lines during N-1 contingencies when an inverter is the only source. To mitigate this, supplemental under-voltage protection ensures the disconnection of the inverter, independent of its control system. However, this protection must be carefully configured to avoid conflicts with regulatory ride-through requirements and protection systems on adjacent lines. The automatic inhibition of the negative sequence elements during N-1 contingencies further enhances system reliability.

The countermeasures discussed are intended to guide protection application engineers involved in integrating inverter-based resources. By fostering discussion, these insights aim to enhance current protection strategies until new technologies independent of the inverter control system become available.

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