

Integrated Protection and Control Architecture for DER-Rich Distribution Systems: SDG&E's Implementation and Field Experience

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Integrated Protection and Control Architecture for DER-Rich Distribution Systems: SDG&E's Implementation and Field Experience

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Abstract—The rapid expansion of distributed energy resources (DERs) is fundamentally altering protection, control, and operational paradigms in electric distribution systems. Utilities are now challenged to maintain high levels of reliability, safety, situational awareness, and service continuity despite increasingly dynamic and bidirectional power flows. Meeting these challenges requires adaptive protection schemes, resilient communications paths, and coordinated control architectures capable of supporting both normal and contingency operations.

San Diego Gas & Electric (SDG&E) has addressed these emerging requirements through the deployment of multiway pad-mounted switches equipped with advanced centralized protective relays at key point of common coupling locations. These relays feature enhanced logic, multiple current transformer and potential transformer inputs, high-speed communications, and comprehensive protection elements—enabling the design of a robust, scalable, and future-ready protection and control scheme.

This paper presents the end-to-end experience of the utility implementing these systems across multiple operating modes, including grid-parallel, grid-island, grid-transition, and black-start conditions. It details the underlying protection settings philosophy, standardized logic sequences, and permissive interlocking strategies that enhance coordination, reduce operational risk, and streamline field deployment.

Grounding practices and transformer sizing methodologies essential for dependable ground fault detection and isolation during islanded operation are examined. Islanding detection techniques—both intentional and unintentional—are presented with supporting results from laboratory validation performed at the integrated test facility of the utility, offering insights grounded in real-world performance.

In addition to protection innovations, the paper introduces the unified control framework of the utility, which is engineered to tightly integrate protection, control, and communications functions in DER-rich environments. At the core of this architecture is high-speed digital input/output communications, enabling deterministic, low-latency exchanges of permissions, statuses, and interlocking signals between relays, site energy controllers, and supervisory systems. The project team involved distribution system operators in the design and testing phases, promoting operator awareness and an effective rollout of the projects.

I. INTRODUCTION

San Diego Gas & Electric (SDG&E) has significantly expanded its battery energy storage system (BESS) and microgrid portfolio in recent years. The utility currently operates approximately 24 BESS and microgrid sites, representing 600 MW of utility-owned energy storage capacity, with more than 40 MW under development. These facilities are

typically located on utility-owned property near existing substations or at strategically important locations where enhanced grid reliability and resilience are critical.

The microgrid system design and operation are implemented by first defining the required system architecture and its operational needs, centered on a four-way pad-mounted switch. Compared to traditional open-air substations, pad-mounted switchgear consolidates switching into a compact, modular enclosure, reducing maintenance, land use, and costs while maintaining reliability.

The adopted switch typically has four connections: BESS, load, utility (grid), and grounding bank. It is monitored via four current transformer (CT) sets on each connection, or way, and two wye-connected potential transformer (PT) sets on the bus and grid sides. The protection and control scheme manages four operating modes: grid parallel, islanded, resynchronization, and black start.

To meet the design and operational requirements, the utility selected a traditional centralized protection and control (CPC) relay as the protective device and controller at the point of interconnection (POI) because of factors such as support for multiple CT and PT inputs for protection and control on multiple ways of the switch, a flexible and expandable input/output (I/O) board, and extensive logic capability. These features allow one relay to handle both protection and advanced automation for the transitions between different operating modes. The extensive logic capability of the relay is used not only for microgrid modes but also for additional applications like automatic transfer and restoration schemes [1].

The selected motor-operated, fast-close, four-way switch, shown in Fig. 1, features a 15.5 kV, 600 A vacuum interrupter for load switching, fault closing, and fault interrupting. Each way includes a three-phase, spring-driven, gang-operated vacuum switch assembly, a motorized linear actuator, and a visible disconnect to verify isolation. The motorized linear actuator on the vacuum switch operating handle provides remote operating capability to support automation requirements.

A key factor in the selection of this switch is its fast-close coil, which reduces closing time from the typical ~10 cycles to ~3–6 cycles, improving distributed energy resource (DER)-to-grid synchronization and reducing transient disturbances during grid and island transitions.



Fig. 1. Inside the Four-Way Pad-Mounted Switch

Another distinguishing feature of the fast-close switch design is the operation of Way 3, the grid-side connection. This position is equipped with a precharged trip-close mechanism that can be electronically or manually trip closed. As the vacuum switch operating handle is moved to the closed position, the solenoid-released trigger holds the spring-driven toggle in an open, charged state. Upon satisfaction of synchronization requirements, the trip-close device is energized, releasing the toggle lock and allowing the vacuum switch mechanism to rapidly close. This fast trip-close action improves DER-to-grid synchronization and reduces transient disturbances during grid and island transitions.

A. Need for Standardization

Microgrid systems can achieve the same outcomes through many different components, designs, protocols, and control architectures—and this complexity is growing as BESS and power conversion system (PCS) technologies evolve rapidly across manufacturers, each with its own operating method and interface. Understanding the specifics of each site and controlling the equipment can therefore become highly complex, with knowledge requirements escalating with every new microgrid. This creates a dilemma for utilities aiming to run all microgrid operations from a central control center, operable by any on-shift operator. Standardization was therefore deemed essential to reduce this complexity and streamline operations.

The utility has a standardized microgrid design including operational modes, permissions requirements, supervisory control and data acquisition (SCADA) human-machine interface screen uniformity, protection and automation settings for the POI relay, interconnection switch position designations, communications protocols, operating procedures and documentation, and technical specifications for contracts.

An inverter screening process is also required to ensure that the utility has the necessary information to review and understand the capability of the inverter to ride through, island, and reconnect with the grid and be compliant with industry standards like IEEE Std 1547-2018, *IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces*.

II. MICROGRID COMMUNICATIONS ARCHITECTURE

The utility control center operator uses the utility SCADA system for visibility of the POI and the microgrid through the flow of supervisory data. The utility SCADA system allows the operator ultimate control of permissions for each operational mode of the microgrid. Once permission for a specific microgrid mode is granted via SCADA, the permission flows to the CPC relay at the POI. The relay processes automation logic based on different statuses and values from the site energy controller (SEC), ground source, and IEEE C37.118 phasor measurement unit (PMU) data to initiate the microgrid automation logic associated with the microgrid control mode for which SCADA permission has been granted. If all the status and analog values satisfy the microgrid automation logic in the relay, permission for the microgrid control mode is sent to the SEC. When permission is granted to the SEC, it monitors PMU data from the CPC relay and supervisory data from the PCS and battery management system of the microgrid site to control both systems and operate the microgrid in the specific mode in which permission was granted. Fig. 2 shows the high-level architecture.

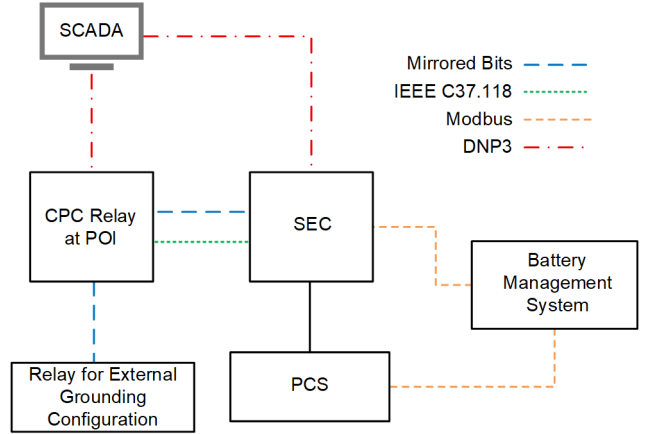


Fig. 2. Communications Architecture for the Microgrid System

III. OPERATIONAL MODES AND SEQUENCE

A. Grid-Parallel Mode

In this mode, the microgrid operates in parallel with the utility grid, with Way 3 closed. The grid serves as an infinite bus, establishing voltage magnitude and frequency references for all DERs within the microgrid. Inverter-based resources, such as photovoltaic systems and BESSs, operate in grid-following (GFL) mode, where their control loops track the grid voltage phasor using a phase-locked loop and inject current at commanded active and reactive power set points. Typical interconnection voltage and frequency are 12 kV and 60 Hz, respectively.

The SEC optimizes DER dispatch for objectives such as peak shaving, active power dispatch, state-of-charge management, or ancillary service provision. The point of common coupling for the utility systems is typically located near the substation and used for isolation and protection of microgrid equipment. This location contains a meter that is

certified by the California Independent System Operator, which is used during closed-loop control for market participation.

The POI is usually at Way 3 of the four-way switch, where the utility service is connected and disconnected. This location is used for closed-loop control in load shifting or ancillary services participation.

B. Grid-Islanded Mode

In islanded mode, Way 3 is open and the microgrid operates as an autonomous electrical island, supplying local loads from internal DERs without grid support. The fundamental challenge in this mode is that there is no external voltage or frequency reference; the microgrid must self-regulate both.

At least one DER transitions to grid-forming (GFM) mode, acting as a voltage source by regulating terminal voltage and frequency. This is typically implemented via droop-based V/f control. A BESS is the most common GFM asset due to its fast response and bidirectional power capability. If multiple GFM sources are present, active power sharing is achieved through frequency droop (f-P droop) and reactive power sharing through voltage droop (V-Q droop), similar to conventional generator droop characteristics.

Load-generation balance is critical in this mode. Any mismatch manifests as a frequency or voltage deviation proportional to the droop gain. The sequence of transitioning from grid-connected to islanded mode is described in detail in Section VI.

C. Resynchronization Mode

Resynchronization is a distinct operational mode in which the microgrid, after operating in isolation, executes a controlled return to grid-connected operation. Functionally, it is the reconnection sequence treated as a managed mode with its own state machine in the SEC.

During resynchronization, the following sequence is performed:

1. The CPC relay monitors both sides of Way 3 via dedicated line-side and bus-side PTs and sends this analog data to the SEC via IEEE Std C37.118, *IEEE Standard for Synchrophasor Measurements for Power Systems*.
2. The SEC checks for healthy grid voltage and performs a voltage regulation mode on the inverter to move the microgrid voltage magnitude so it matches the grid voltage magnitude from the CPC relay. Once the magnitude is within a 1 percent difference, a separate control loop frequency set point makes the bus voltage angle equal to the grid voltage angle. The controller tries to hold that angle difference as close to zero as possible, keeping it within 5 degrees of normal. After satisfying these requirements, the SEC sends a close request to the CPC relay while maintaining closed-loop control.
3. The CPC relay runs its own independent synchronism-check element (25C) and sends the close command only when 25C asserts and the SEC permissive signal is received.

D. Black-Start Mode

A black start defines the capability of the microgrid to energize a de-energized network from a completely dead state—with no external grid and no residual voltage on the distribution system—and restore power to critical loads without any external source of support. The utility uses this mode if the system anti-islands unexpectedly or fails to island during one of the transition sequences. System checks and root-cause analysis of the tripped system may be required before bringing the microgrid and customers online.

For DER interconnection applications at the utility, BESS systems in GFM mode connected on Way 1 are used as black-start assets.

There are two schemes: full load bank and partial load bank. Both are programmed with the ability to accomplish a black start with either remote (via SCADA) or local controls.

The full load bank scheme allows the inverters to have the controls necessary to instantaneously turn on all their capacity and seamlessly carry the entire load on the island. For this reason, the CPC relay keeps Way 2 closed prior to ramping the DER assets.

In the partial load bank scheme, the inverters have one master, which comes online first but cannot handle the full load of the island. The master ramps up the lump system until it is ready to pick up the full load. Way 2 is initially open. The CPC relay waits to receive all inverters in running and ready status before closing Way 2 to pick up the load. In this way, the control scheme prevents the inverter from picking up the load prematurely. The selection of the scheme is dependent on the inverter control scheme capability.

The black-start sequence is carefully staged with the following steps for the partial load bank scheme:

1. The microgrid is standing by, and the utility grid source is no longer available.
2. System operators send permission to the CPC relay through remote bits to initiate the sequence. The relay confirms three conditions: bus undervoltage (271P1T and 272P1T) at the switch, Way 3 in open state, and the DER in run mode, which means the CPC relay is effectively communicating with the inverter through the SEC. The black-start mode is enabled if all these conditions are true. During this state, Way 1 remains closed, whereas Way 2, Way 3, and Way 4 are open.
3. The grounding bank (Way 4) is automatically closed in after receiving the black start-enabled mode permissive, but only if the DER is in run mode. The bank provides a ground reference for the inverter in GFM mode.
4. The black start-enabled mode status is sent to the SEC through high-speed Mirrored Bits communications. The SEC then places the inverters in GFM mode. The inverters start up in a current-limiting mode while stabilizing the voltage. This ramping startup energizes local transformers and auxiliary loads without tripping on dead-bus energization or inrush.
5. Once the SEC confirms that all available inverters have started, it issues the island ready input to the

relay. The relay enables auto-island or commanded island and disables black-start mode, so it is ready to island.

6. The relay performs logical checks on the system and, if successful, closes the customer load on Way 2 back into the microgrid.

IV. GROUNDING REQUIREMENTS

The utility implements an effectively grounded distribution system across its service territory, per IEEE Std C62.92.1, *IEEE Guide for the Application of Neutral Grounding in Electrical Utility Systems*. An effectively grounded system is one in which the neutral is connected to earth through a sufficiently low impedance so that overvoltages during line-to-ground faults are limited to safe levels. In practical terms, this means the ratio of zero-sequence to positive-sequence impedance (X_0/X_1) is controlled so that the voltage on unfaulted phases does not rise significantly above nominal (typically less than about 1.25 pu). This type of grounding ensures that ground fault currents are large enough for reliable protection operation while simultaneously preventing damaging overvoltages on equipment and insulation.

A key aspect of this analysis is the management of zero-sequence current ($3I_0$), which directly influences ground fault detection and relay coordination. Transformer winding configurations determine whether zero-sequence current is passed between the DER and the utility, blocked, or locally sourced.

A high-side delta-wye grounded (Δ/Y_g) transformer configuration, as shown in Fig. 3, was chosen, as it demonstrates improved performance in grid-parallel operation by blocking zero-sequence current flow to the utility system and thereby preserves the settings of upstream devices. However, in islanded operation, the absence of a grounding reference for faults on the delta side of the DER interconnecting transformer on Way 1 or load circuit (Way 2) can lead to overvoltage conditions and limit the ability to serve line-to-neutral loads unless an external grounding source is provided. For that reason, a switchable grounding bank in either an external or internal configuration is used. The bank is closed in during grid-islanded mode and remains open during grid-parallel operation to achieve the best of both worlds.

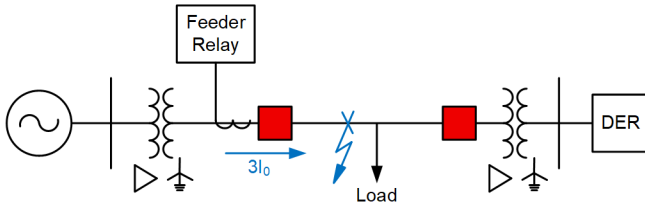


Fig. 3. Δ/Y_g DER Interfacing Transformer

In the ground bank internal configuration, as shown in Fig. 4, the grounding bank is directly integrated into the DER interconnection scheme and is connected on Way 4 of the switch. It is controlled through the CPC relay. During island formation, the relay closes the Way 4 grounding path, allowing the DER to establish an effective ground reference locally. This

approach ensures that, once separated from the grid, the DER system remains effectively grounded, enabling proper detection and clearing of ground faults.

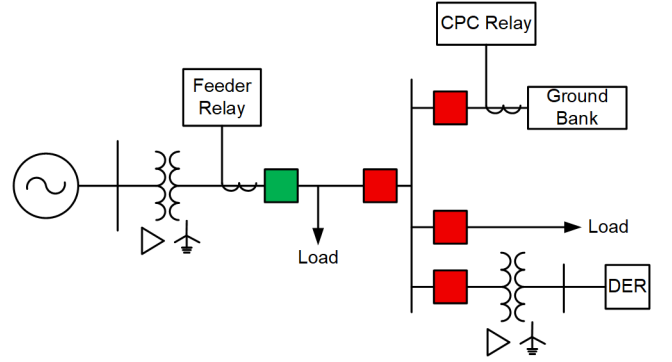


Fig. 4. Simplified Single-Line Diagram of Ground Bank Internal Interconnection

The ground bank external configuration shown in Fig. 5 achieves similar functionality, but it is through an independent grounding control device, generally a relay. In this arrangement, the grounding bank is not directly tied to the main interconnection pad-mounted switch but instead is closed through a dedicated grounding switch during islanded operation. This provides additional flexibility in system design and allows grounding control to be coordinated independently of the main DER interconnection pad-mounted switchgear. In this configuration, the grounding bank status is passed to the CPC relay via high-speed Mirrored Bits communications. This configuration is helpful in situations where Way 4 on the pad-mounted switch might be required for future load connection.

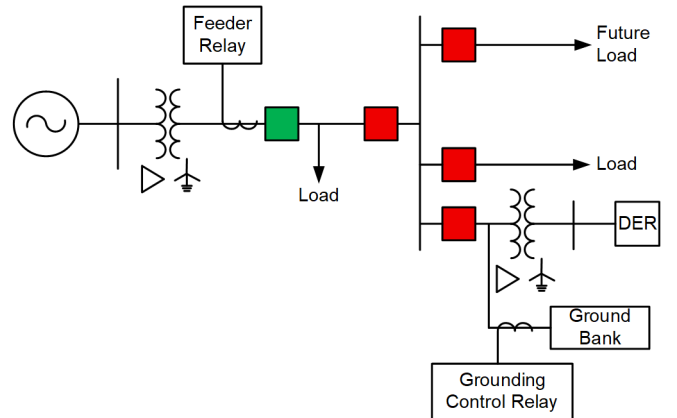


Fig. 5. Simplified Single-Line Diagram of Ground Bank External Interconnection

The utility implements a make-before-break scheme for the breaker feeding the grounding bank. The conditions that initiate the automatic closing of that breaker for commanded island, auto-island, and black-start sequences are as follows:

- The CPC relay has the DER enabled latch engaged.
- The CPC relay receives the desired permission for commanded island, auto-island, or black start.
- Way 3 (grid) is in the closed state.
- The grounding bank breaker motor position is open.

The conditions that initiate the automatic opening of that breaker are as follows:

- The CPC relay has the DER enabled latch engaged.
- The CPC relay registers that all permissions required for commanded island, auto-island, and black start are disabled.
- Way 3 (grid) is in the closed state.
- The grounding bank breaker motor position is closed.

The design and sizing of the grounding transformer are critical to ensuring reliable operation. Several parameters are considered, including winding configuration, system voltage, insulation level, neutral current capability, and available fault current. Both zigzag and wye-delta transformer configurations can provide an effective ground reference; however, the wye-delta configuration is typically preferred by the utility due to its availability, higher kVA ratings, and flexibility. In particular, the delta winding provides a useful interface for auxiliary equipment, such as load banks or temporary generators, and supports greater tolerance to system unbalance.

Proper sizing of the grounding bank ensures that it can handle continuous neutral current resulting from load unbalance, as well as transient fault current contributions during ground faults. For example, a typical design constraint limits neutral current to approximately 100 A under steady-state unbalance conditions to avoid overheating and equipment damage. Additionally, system voltage and insulation requirements, such as a 12 kV class system with a 110 kV basic impulse insulation level, must be considered to ensure the grounding transformer can withstand both normal and transient operating conditions.

V. PROTECTION PHILOSOPHY AND SETTINGS

Protection settings for the relay shall accommodate both grid-parallel and islanded operating conditions while maintaining coordination, dependability, and security. The utility does not apply the concept of group changes in the relay to switch between these modes. Instead, they use supervision logic in the same group.

A. Grid Parallel

In this mode, the microgrid operates in parallel with the area electric power system (area EPS) through the utility-side position of the four-way pad-mounted switch, identified in this implementation as Way 3. Fig. 6 shows the position of all the four ways in the normal state during this mode.

During normal grid-connected operation, the DER operates in GFL mode. Because the area EPS is the dominant voltage source in this mode, the DER does not intentionally regulate the microgrid voltage or frequency while the system remains paralleled to the grid.

In this section, only the ground bank internal configuration is discussed. Keeping the grounding bank on Way 4 disconnected avoids introducing an additional ground source in parallel with the utility system, which could alter zero-sequence current paths and affect upstream ground-fault coordination [2] [3].

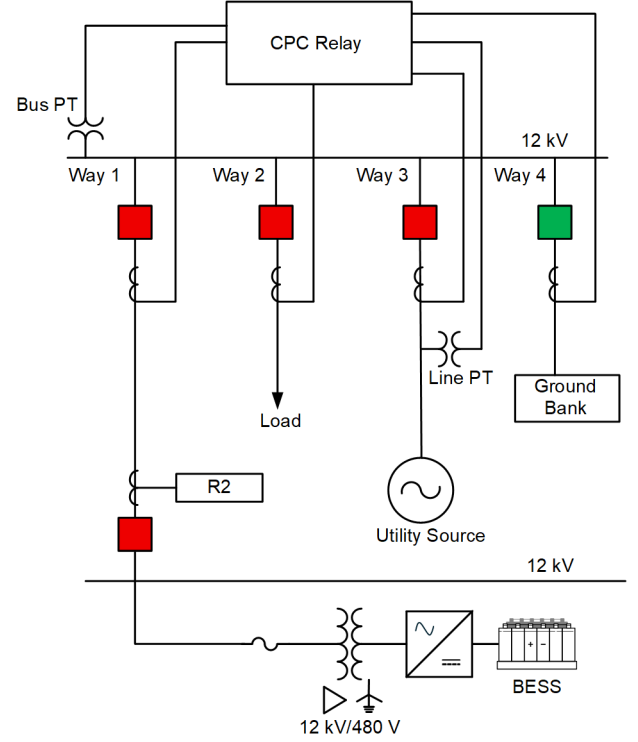


Fig. 6. Switch Configuration During Grid-Parallel Mode

The protection philosophy in grid-connected mode is based on the availability of strong utility fault current from the area EPS. Conventional phase and ground overcurrent protection can therefore be applied where appropriate, particularly for faults on the DER side on Way 1 or load side on Way 2 of the four-way switch.

For Way 1, protection is associated with the DER asset and its interconnection equipment. Conventional phase and ground overcurrent elements are enabled on this way to coordinate with the downstream DER relay, shown as R2 in Fig. 6, and with upstream feeder protection. For transformer or inverter-side faults, the transformer high-side fuse, where applied, is expected to provide primary protection, with Relay R2 acting as backup. Relay R2 and low-voltage assets at the 480 V side are coordinated based on guidelines from IEEE Std 242, *IEEE Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems*, which does not fall under the scope of the utility. For faults upstream of Relay R2 but downstream of Way 1, overcurrent elements programmed for Way 1 open that way. If, for some reason, the switch or Way 1 fails to clear the fault, then the feeder relay or upstream recloser is the next line of defense. It is set such that it overreaches into the downstream zone of protection.

When the ground bank external configuration is selected for a site, Way 1 is also tripped if the ground bank is faulted and the ground bank switch is closed. This occurs through Mirrored Bits messages coming from the grounding control device or the relay. As previously discussed, the external ground bank would not be in service during grid-parallel operation.

For Way 2, protection is associated with the customer's critical load served by the microgrid. Conventional overcurrent protection is applied to protect against load-side faults and

coordinate with downstream protective devices and upstream feeder protection.

For Way 3, the utility-side connection, the philosophy is different. The area EPS feeder relay or upstream protective device is expected to clear utility-side faults. After upstream fault clearing, DER-side isolation is handled by a combination of inverter anti-islanding behavior and the undervoltage logic in the CPC relay. The following subsection describes this in additional detail.

During the fault, the DER may contribute limited current through its interconnection transformer; however, this contribution is not relied upon for primary utility-side fault clearing.

After the upstream feeder breaker or other area EPS protective device clears the fault, the microgrid may experience one of several outcomes depending on site status and operating permissives:

- If auto-island is armed, the site is in a standby condition in which the inverter controls have been prepared to transition to islanded operation following a loss of the utility source. In this condition, the DER may transition from GFL to GFM mode and continue supplying local load, provided all required permissions are satisfied. More on this is explained in Section VI.A in the paper.
- If auto-island is not armed, the inverter follows its anti-islanding behavior and ceases to energize in 2 s, per IEEE 1547 or California Electric Rule 21. In this case, the microgrid does not intentionally continue serving load as an island but there is no source feeding the fault.
- If the local voltage at the four-way switch collapses or remains depressed, undervoltage protection provides an independent isolation layer in the CPC relay. This is particularly important when the upstream source has opened and the remaining DER contribution is limited or controlled only by the inverter, which is running as a current-limited GFL device.

The undervoltage logic is therefore treated as a protection layer that supports source isolation under abnormal voltage conditions. The abnormal voltage can stem from either faults or a loss of a grid connection after the area EPS source has opened. Three levels are chosen based on shall-trip settings, per IEEE 1547-2018 [4] for Category III DERs to comply with the ride-through requirements: the Level 3 element at 0.7 pu of nominal secondary voltage at a 1 s delay, the Level 4 element at 0.5 pu at a 0.5 s delay, and the Level 5 element at 0.25 pu at a 0.1 s delay. The operating times of these elements are faster than the anti-islanding detection of the inverter (2 s), and therefore these elements will clear the fault faster than the inverter's own protection. These elements will trip not only Way 3 but also Way 1 and Way 2 to avoid inverters running in GFL mode so that they can support their load on Way 2 during this unexpected island formation. These elements are also coordinated with the undervoltage trip set points in the inverter. The inverter low-voltage ride through and trip are set at 0 percent for 300 s, whereas high-voltage trip and ride through

are set at 110 percent of nominal for 12 s. These elements in the CPC relay are engaged only when undervoltage trip supervision logic is qualified, as shown in Fig. 7. When DER run mode is enabled, the CPC relay, as a master, is active to send and receive permissions to and from the SEC. A healthy communications channel between the SEC and CPC relay is also required. Additionally, inverters also have their own underfrequency and overfrequency ride-through and trip settings compliant with IEEE 1547-2018 to address grid-side abnormalities.

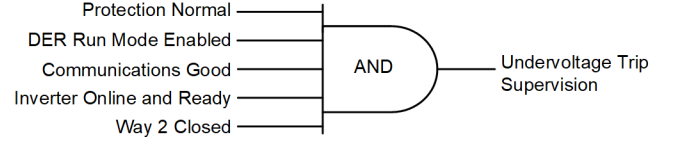


Fig. 7. Undervoltage Supervision Logic

For Way 4, no protection is enabled because the ground bank remains disconnected.

B. Grid Islanded

In this mode, utility feed Way 3 is open and Ways 1, 2, and 4 are closed, as shown in Fig. 8.

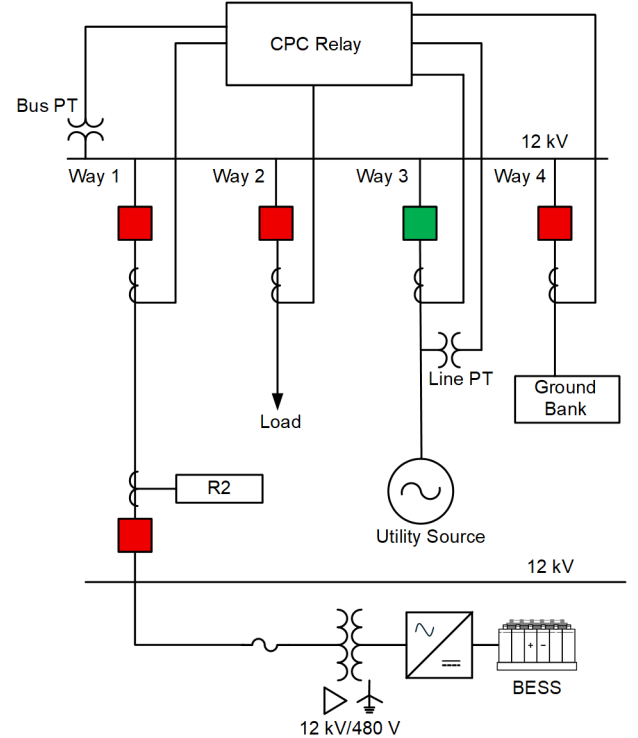


Fig. 8. Switch Configuration During Grid-Islanded Mode

During this mode, protection settings explicitly account for the limited and controlled fault current contribution characteristic of inverter-based DERs, as they are the only source of fault contribution for phase faults. Conventional overcurrent protection is not relied upon as primary fault detection due to insufficient fault current margin above load. Instead, voltage-dependent protection elements are used. Multistage undervoltage (27) elements are applied with coordinated time delays such that significant voltage depressions associated with true faults result in faster clearance,

while smaller voltage deviations are subject to longer delays to ride through transient disturbances and control actions.

The same undervoltage levels for the grid-connected mode were found to be functional even in grid-islanded mode. Since IEEE 1547 does not cover grid-islanded mode, the utility had to run simulation studies with end-of-line impedance faulting to confirm the same set points were good.

Two levels of undervoltage-supervised phase overcurrent elements (50C) were selected as well to cover phase faults. The settings were set at 110 percent of the full load capability of the microgrid, which came from the power flow program. During islanding mode, the microgrid does not see more than 120–130 percent of full load output from the inverter. Setting the overcurrent element at 110 percent ensures the relay initiates the tripping sequence for any fault on the circuit if the voltage sags and is sustained below 0.9 pu and 0.8 pu of nominal secondary after 1 s and 0.5 s, respectively. Inverters are running in GFM mode during this state but regardless of its mode, it should still output current greater than 110 percent. These elements are programmed to operate only Way 2, where the critical load is connected.

Similarly, two levels of undervoltage-supervised ground overcurrent are selected. The settings are based on 30 percent of the full load capability of the microgrid per the data run in the power flow program. Setting the 67G element at 30 percent ensures the relay initiates the tripping sequence for any fault on the circuit if voltage sags to similar values set for phase overcurrent.

Additionally, one level of the undervoltage-supervised negative-sequence overcurrent element is enabled to detect sensitive line-to-line faults on Way 2. The settings are based on the available negative-sequence current ($3I_2$) seen for end-of-line faults on the microgrid in combination with the four-way switch witnessing a loss of voltage (0.9 pu) for a sustained amount of time of 1 s. A setting of 30 percent of $3I_2$ measured for end-of-line faults was selected to securely account for all line-to-line faults on the way. Similar to undervoltage elements, impedance faulting at the end of the line helps select the appropriate $3I_2$ value. Inverters are running in GFM mode and are capable of producing $3I_2$ for this element to function.

Way 1 faults between the four-way switch and the 12 kV downstream bus are protected by Relay R2 since the BESS is the only source of fault contribution. Faults downstream of R2 are protected by the inverter.

For ground faults in the grounding bank on Way 4, one level of the undervoltage-supervised ground overcurrent element is chosen. This element is connected to the Way 4 CT looking at the grounding bank. The ground overcurrent settings are set at 30 percent of the full load capability of the grounding bank and are dependent on the four-way switch seeing a loss of voltage of 0.75 pu of the nominal for a sustained amount of time of 1 s. This setting is set above the unbalance but sensitive enough to trip Way 1 for faults downstream of Way 4 to isolate the source. Way 4 is never tripped during islanded mode.

VI. ISLANDING DETECTION METHOD

When a grid-tied microgrid loses its connection to the utility network, the question of whether that separation was planned or forced determines everything that follows—from the safety of field personnel to the continuity of power for critical loads. The microgrid architecture of the utility therefore applies two distinct modes of transition into island operation: auto-island and commanded island. The subsections that follow describe the purpose of each mode and explain the detection and control logic that governs the transition.

A. Auto-Island

Auto-island is fundamentally a protective response to an unplanned loss of the utility source. It becomes relevant in scenarios where adverse conditions—most notably high winds during elevated fire-risk periods—make a grid outage likely but not yet imminent. In these situations, system operators anticipate a possible disturbance without knowing exactly when, or whether, the circuit will need to be de-energized. The auto-island mode bridges this uncertainty. The site is placed on standby for autonomous separation, ready to transition the moment the grid is lost.

The trigger for auto-island is the opening of the upstream feeder breaker or recloser that sources Way 3. This loss of the utility source is detected automatically, without requiring operator intervention, and the system responds accordingly.

During this mode, the energy management strategy adopted is to maintain a state-of-charge hold at 95 percent. By keeping the BESS near full capacity rather than cycling it through normal charge and discharge operations, the system maximizes its available energy reserve—and therefore the duration for which the islanded microgrid can sustain customer loads without utility support.

1) Sequence of Operation

The auto-island transition occurs through a carefully coordinated sequence involving the SEC, the inverters, and the CPC relay controlling the switch. The design ensures that the inverters are in the correct operating state before the transition to minimize disruption and inadvertent inverter trips.

1. System operators grant permission for the site to island autonomously if a disturbance is detected on the circuit. This authorization arms the auto-island logic.
2. The SEC pushes updated inverter settings that prepare the inverters for a potential transition to GFM mode. It is important to note that the inverters continue operating in the currently selected PQ (active and reactive power) or GFL mode. The grounding bank is also automatically closed in from the CPC relay at this point, establishing the ground reference required for GFM mode.
3. The CPC relay monitors the grid in real time. Upon detecting a loss of the utility source from a customized fast rate-of-change-of-frequency (ROCOF) element (81RF), the relay issues a trip command to open Way 3 and electrically isolate the microgrid from the feeder.

4. The inverters sense the collapse of the grid voltage following the breaker opening and autonomously transition from GFL (P-Q) to GFM (voltage-source) mode. The goal is to have the CPC relay open Way 3 before this inverter mode transition. The SEC is also programmed to send a Mirrored Bits message to the CPC relay to trip open Way 3 if the 81RF element is taking a long time. This does not remove the need for the 81RF element because the utility cannot be certain about the logic in the SEC, as its programming is handled by a third-party contractor. Also, they are not confident that the inverter will always send a command from the PCS to the SEC, which actually initiates the transmit Mirrored Bits message in the SEC.
5. The microgrid operates independently, with the inverters regulating voltage and frequency and supplying the customer load. Whether this transition is seamless—imperceptible to sensitive loads—or involves a brief interruption depends on the speed and coordination of the inverter response relative to the magnitude of the grid disturbance.

2) Auto-Island Detection Logic in the CPC Relay

The utility developed a customized synchrophasor-based ROCOF element in the CPC relay, which was possible because of the extensive logic capability of the relay with processing times that are the same as a dedicated protection element. When the scheme was designed, it was expected that the synchrophasor-based logic would be somewhat faster than the logic developed using local measured frequency. This was under the assumption that the local measured-frequency method would have a longer filter and frequency-tracking delay.

The PMU function, compliant with IEEE C37.118-2005, in the relay derives frequency and its rate of change from the positive-sequence voltage phasor, coming from the Way 3 side PT; no zero-crossing detection or dedicated frequency-tracking algorithm is used. The raw 8 kHz data in this relay is passed through a low-pass filter. The filter coefficients depend on message rate, nominal frequency, and filter type. A fast-response filter type has a higher cutoff frequency. The response in the frequency domain is wider and faster in time domain. The delay is about 1 cycle for a 60 Hz signal when the message rate is 60 samples per second (sps). Another filter type is narrower in the frequency domain but slower in the time domain. The utility experimented with the fast filter within the framework of the 2005 standard.

The PMU uses the angle of the positive-sequence voltage that is computed every cycle (60-messages-per-second rate) and compares it against the previous cycle to calculate

frequency deviation as shown in (1).

$$f_k = \frac{\theta_k - \theta_{k-1}}{\Delta t \cdot 360} \quad (1)$$

Here, θ_k and θ_{k-1} are the positive-sequence voltage angles at consecutive cycle boundaries, and Δt is the elapsed time between those measurements in seconds. A grid operating at exactly 60 Hz produces an angle increment of 360 degrees per cycle, giving $f_k = 0$. A decelerating islanded system—one in which load exceeds generation—produces a smaller angle increment, yielding a negative f_k . An accelerating island produces a positive f_k .

A single per-cycle angle difference that is sensitive to noise and errors could result in spurious frequency excursions. The PMU function therefore averages a window of f_k samples. A smooth frequency application uses 9 cycles of data for the averaging calculation, which is acceptable for metering and reporting applications but could be slow for rapid frequency fluctuations and high-speed protection. A fast frequency application, on the other hand, only takes 3 cycles but may contain low-level oscillations.

With a clean, averaged frequency estimate, the PMU function computes the ROCOF, also written df/dt , using (2).

$$\frac{df}{dt_k} = \frac{f_{avk} - f_{avk-1}}{\Delta t} \quad (2)$$

This quantity is published as the analog output DFDTM.

The utility used the fast frequency application because of the speed requirements. Some inverters that were deployed can switch between modes within 4 ms but generally take 5–6 cycles to stabilize the voltage.

Before publishing frequency data to the protection logic, the PMU enforces a two-condition check:

- The measured frequency deviation must fall within ± 20 Hz of nominal.
- The positive-sequence voltage magnitude (secondary) must exceed $0.1 \cdot V_{\text{NOM}}$. Below this threshold, the phasor angle becomes unreliable and the frequency calculation is meaningless.

When either condition is violated—as occurs during a bolted fault that collapses the voltage or drives the frequency far from nominal—the PMU holds FREQPM at its last valid value, forces DFDTM to zero, and clears FROKPM. This built-in signal conditioning is important. It ensures that a severe fault does not produce a spurious ROCOF spike that could be misinterpreted as an islanding event.

3) 81RF Detection Characteristic

The characteristic programmed through logic is shown in Fig. 9. Under normal, grid-parallel operation, both x-axis and y-axis quantities remain near zero and the operating point sits close to the origin.

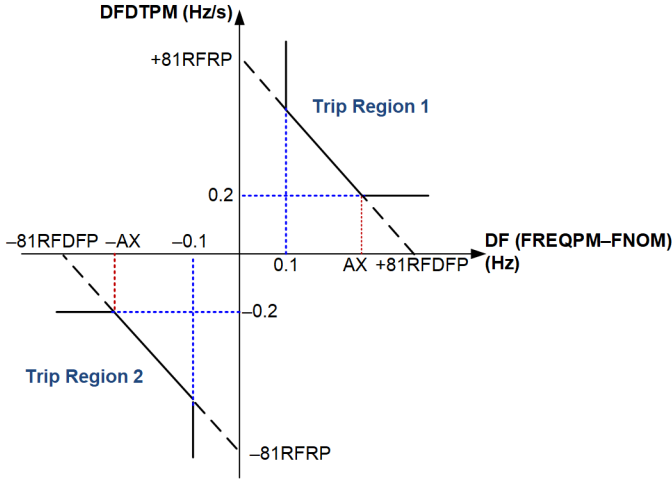


Fig. 9. 81RF Detection Characteristic

When islanding occurs, the balance between generation and load within the island is almost never perfect. Higher generation causes positive frequency deviation and a positive DFDTPM, and the operating point migrates into Trip Region 1. Higher load causes deceleration, driving both quantities negative and moving the operating point into Trip Region 2. The shape of the boundary between the deadband and the trip regions is controlled by two relay settings:

- **81RFDFF:** This is the frequency deviation pickup threshold in hertz. A setting of 1 Hz was chosen. This setting keeps the characteristic intuitive and linear as it falls beyond the 0.92 Hz intersection point shown in Fig. 9 as AX. At a 1 Hz deviation, the relay trips even with zero ROCOF. A block is issued if the deviation is smaller than 0.1 Hz to distinguish it from normal grid switching events, large motor starts, etc.
- **81RFRP:** This is the ROCOF pickup threshold in hertz/second. This setting defines the vertical extent of the deadband and the slope of the characteristic, allowing the element to discriminate between fast-changing islands and slower disturbances. The value of 2.5 Hz/s was selected and turned out to be good for the application, as it is aggressive enough to capture the rapid frequency drift that accompanies a true island yet conservative enough to avoid asserting during nearby faults or large load-switching events. A block is issued if ROCOF is smaller than 0.2 Hz/s.

This element has no intentional pickup delay, which speeds up the detection. A dropout delay of 1 cycle was chosen to avoid chattering at the characteristic boundary during borderline conditions.

Additionally, the following blocking conditions, which are indicative of an active fault rather than an islanding event, were applied:

- Phase current on Way 3 is greater than 5 A secondary (above load current).
- Bus PT voltage at the four-way switch is less than 60 percent V_{NOM} . Severe voltage depression—below 60 percent—signals either a close-in fault or a catastrophic voltage collapse. Under these conditions,

the positive-sequence phasor angle from which frequency is derived becomes too uncertain to support reliable protection decisions.

4) Final Island Command

Even after the 81RF characteristic is satisfied and no blocking condition is active, the relay does not immediately open Way 3. There are a few other conditions that must be confirmed, as shown in the logic diagram in Fig. 10. Of them, the notable ones related to inverters are:

- **Inverters ready for island permission:** This received Mirrored Bits message is transmitted from the SEC to the relay via high-speed communications, confirming that the inverter firmware has successfully received and applied the pre-island settings issued by the SEC in Step 2 of the operating sequence section in Section VI.A.I. Without this confirmation, the relay cannot be certain the inverters are configured for GFM operation.
- **Inverters online and ready:** This bit confirms that the inverters are actively generating power and are not in fault, derating, or lockout condition. An inverter that has tripped internally cannot transition to GFM mode, and opening the POI without a functional voltage source would result in a complete loss of power to the customer loads.

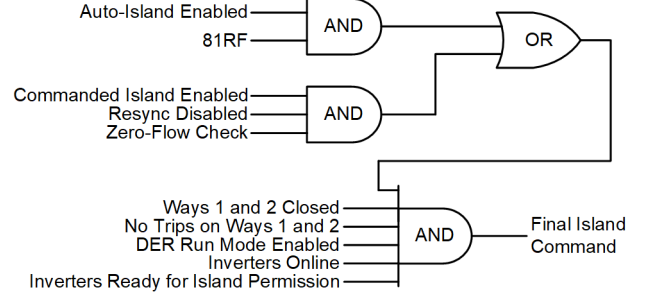


Fig. 10. Final Island Command Logic

B. Commanded Island

This mode is used for controlled offloading of customers from the grid, without disturbance to their service, in preparation for a planned outage on the circuit for repairs and upgrades. In wildfire-prone areas, the utility adopts proactive public safety power shut-off events. Commanded islanding allows them to island critical loads at will before such events. These loads remain powered through the BESS when a microgrid forms.

A zero-flow check is required for commanded islanding, which ensures that the BESS can safely transition the microgrid without system collapse or equipment damage. When an island contains only the BESS as the power source, it lacks the mechanical inertia of traditional generators to absorb sudden power unbalance. The following reasons further highlight the need to have zero flow:

- If significant power is flowing across the POI at the moment of separation, matching that exact load instantly is difficult. Dropping a large export or import

causes severe, instantaneous voltage and frequency excursions that can trip the inverter.

- If the microgrid is importing heavily from the utility, opening the breaker forces the inverter to instantly pick up that deficit. If the deficit exceeds the instantaneous power rating of the inverter, the system shuts down immediately due to overcurrent.
- Opening the four-way switch while high current is flowing creates electrical arcing across physical contacts. Minimizing current flow to near zero extends the operational lifespan of the switching equipment and ensures a clean mechanical separation.
- During a planned islanding event, the inverter must transition its control topology from GFL to GFM. This transition is highly sensitive and succeeds best when net power exchange is minimal.

The utility plans the sequence carefully through the following steps:

1. System operators provide permission to initiate the sequence to ramp the load to zero flow at the POI. This is done via the local-area distribution controller, which the operators can remotely log in to. The

controller monitors the POI meter and dynamically adjusts the inverter active (P) and reactive (Q) power output to drive net utility exchange to zero.

2. The SEC issues inverter settings to prepare for islanding while controlling the power flow to hold at 0 kW. The grounding bank is then closed in.
3. Once the SEC observes the load between ± 5 percent of the nominal rating, it issues the request to open the POI or Way 3 to the CPC relay.
4. The CPC relay performs logical checks on the state of the system and, if successful, operates the open motor.
5. The microgrid continues to operate, supporting the customer load with a seamless transfer.

The final island command can come either from the auto-island or commanded island, as shown in the logic in Fig. 10.

C. Event Analysis: Successful Auto-Islanding

This section describes a successful auto-islanding event that was carried out during field commissioning. The substation feeder breaker was manually opened to verify the performance. Fig. 11 shows the event captured from the CPC relay.

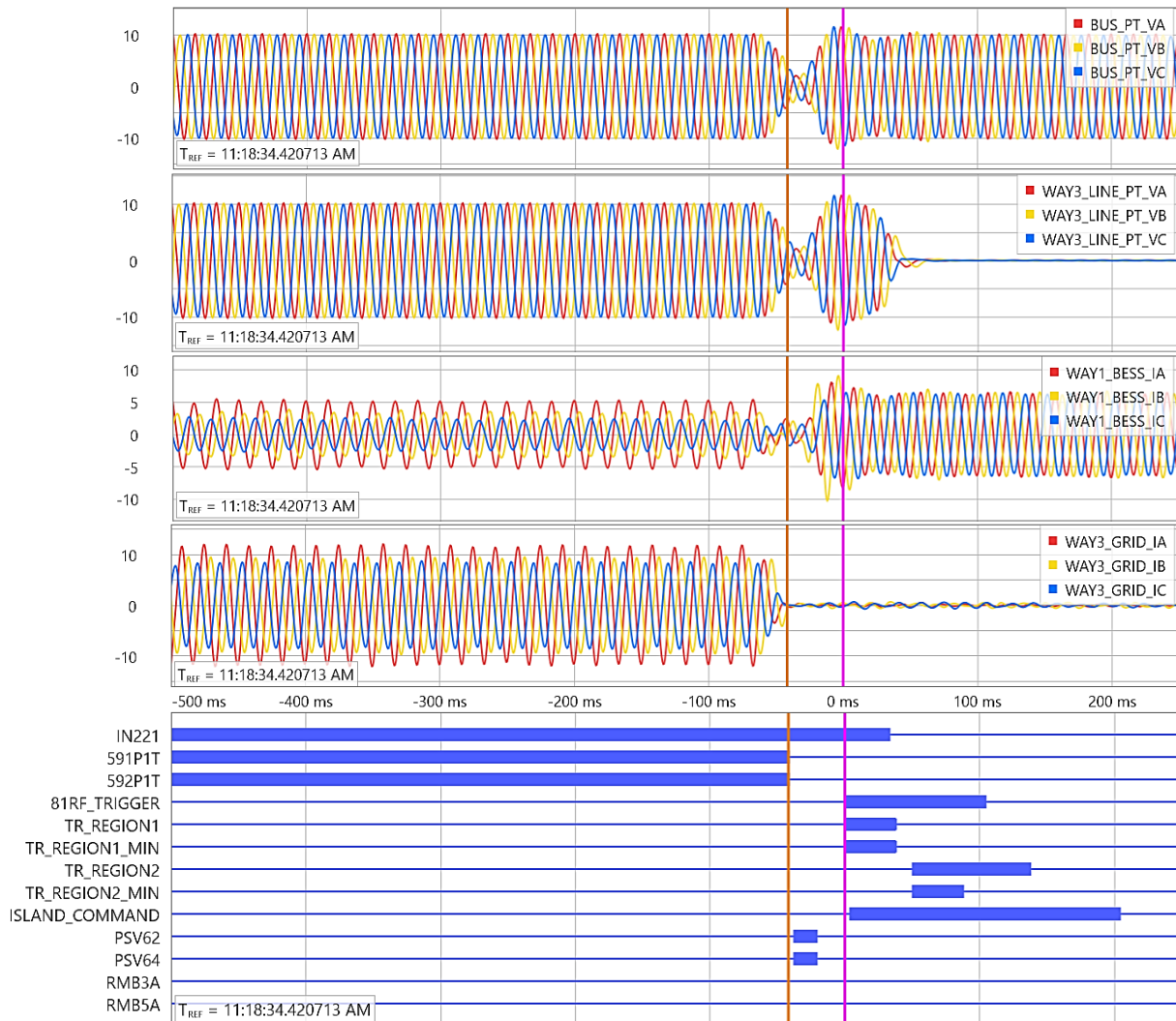


Fig. 11. Auto-Islanding Event From CPC Relay

The orange cursor highlights when the Way 3 grid-side connection lost the current due to the feeder breaker opening. This is corroborated by the dropout of 592P1T that indicates a loss of voltage on Way 3. After 2.5 cycles, the CPC relay triggered 81RF detection, as shown by the magenta cursor. The inverter, however, quickly transitioned to GFM mode as it was ramping up the voltage, as shown by the voltage waveforms right before magenta cursor. This indicates that the inverter transitioned from GFL to GFM faster than the relay operated on island detection.

The TR_Region1 bit indicates that the trigger occurred due to accelerating ROCOF. It might be a bit misleading because the bit triggered when the voltages were ramping up, indicating a decelerating ROCOF. However, it triggered for the drop in voltage that occurred a few cycles prior because of the delay of the fast filter in the synchrophasor and the averaging of four samples in a moving window as explained in Section VI.A.2. The TR_Region2 bit asserted later, and it indicates the 81RF pickup due to decelerating ROCOF during voltage buildup.

IN221 is showing the 52A status of Way 3. IN221 deassertion indicates Way 3 opened a few cycles after the 81RF trigger.

The Way 3 side voltages collapsed but the bus voltages remained steady, further corroborating that Way 3 opened but the inverter in GFM mode supplied the required bus voltage.

VII. TESTING AND COMMISSIONING PRACTICES

The utility requires each microgrid project to be commissioned following a test procedure that validates each

operating mode of the microgrid site and its components before it is placed in service. To reduce risk to the distribution system, a test environment is inserted in between the POI (four-way production switch [FWPS]) and the point of common coupling (12 kV switchgear) for the microgrid site. Fig. 12 shows the test setup for island configuration using load banks, and Fig. 13 shows the setup for grid-parallel mode.

The test environment includes the following:

- A four-way test switch (FWTS)
 - Identical make, model, and manufacturer as the FWPS
 - Identical POI relay and settings
 - Identical switch way designations
- Resistive load
 - Sectionalizing switchgear
 - Step-down transformers
 - Resistive load banks

The FWTS must be identical to the FWPS to allow tests completed in the test environment to validate the production SEC without affecting the distribution system, while still validating communications and controls for each operational mode.

The commissioning of the microgrid sites validates two main elements: controls and power quality. Controls validation includes communications checks, automation verification, and sequential permission validation. The POI relay exchanges operating permissions with the SEC via high-speed Mirrored Bits messages. Transmit bits carry permissions from the POI

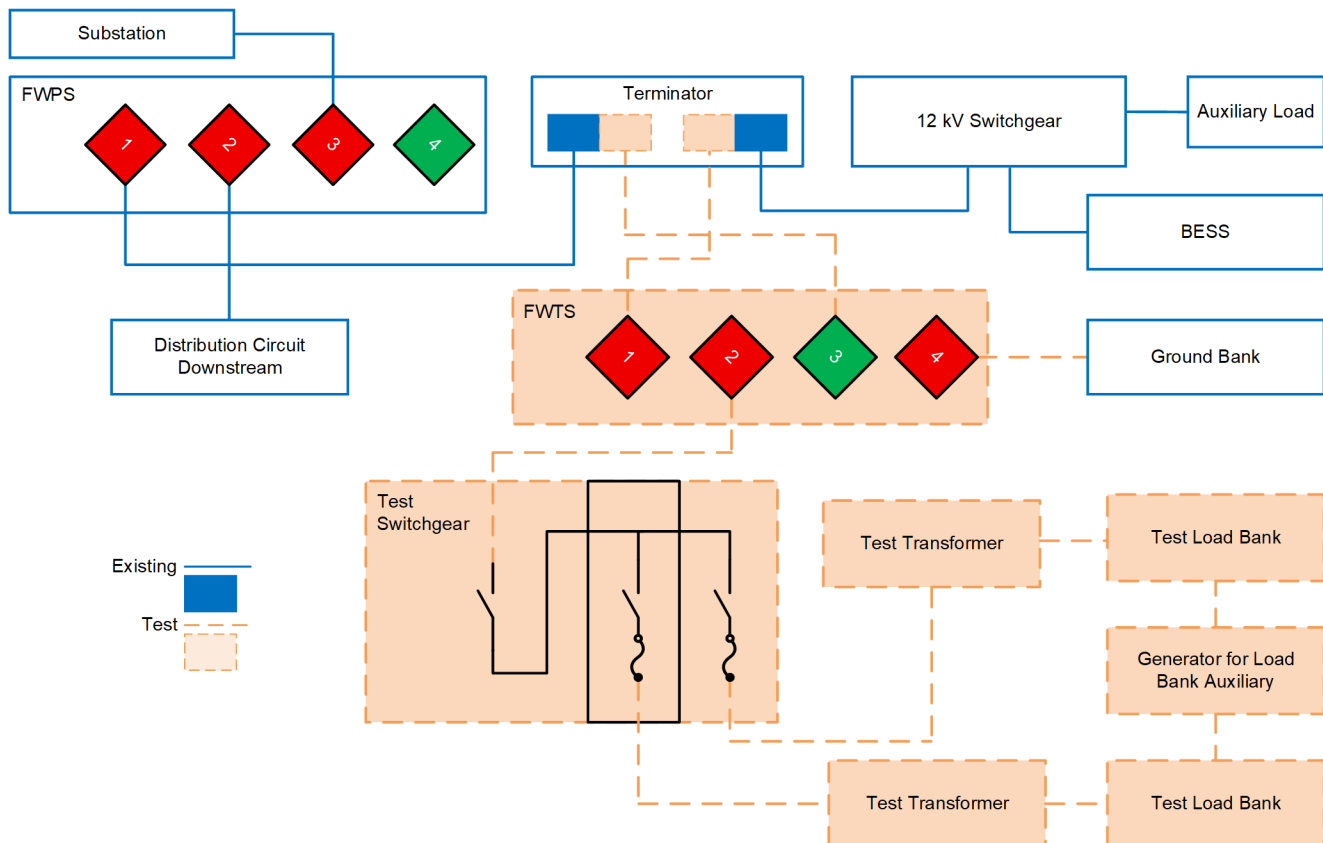


Fig. 12. Test Setup for Island Configuration

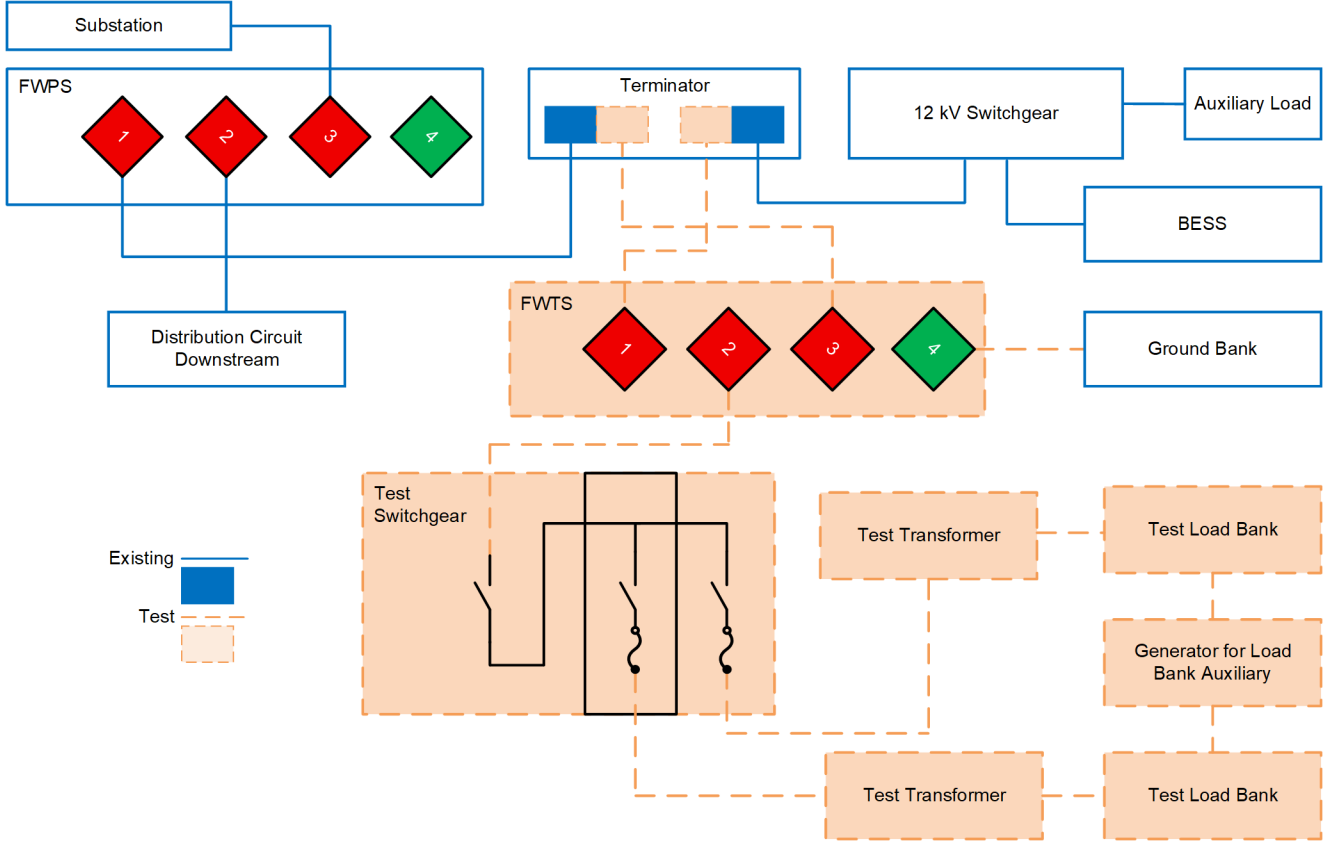


Fig. 13. Test Setup for Parallel Mode

relay to the SEC, whereas receive bits carry status assertions from the SEC back to the POI relay. No operating mode is commissioned until the preceding mode has passed all test cases and results have been recorded. This prevents unsafe closed-loop sequences from executing before the open-loop building blocks have been individually verified. In addition to the controls validation, power quality is monitored closely to confirm the microgrid is importing and exporting acceptable power prior to allowing interconnection to the distribution system.

A. Roles and Responsibilities

The roles and responsibilities of testing and commissioning a microgrid site are split between areas of expertise. The microgrid commissioning engineer submits all prework requests, directs utility switching to isolate the microgrid site from the distribution system via the utility four-way switch, facilitates the interconnection and energization of testing equipment including interconnection of an FWTS, conducts daily safety tailgates, coordinates the test equipment and the microgrid site switching for each test case, records results, and validates if the microgrid is operating as intended. The relay and switch operator is a qualified electrical worker who performs all medium-voltage switching, connects to the relay via laptop, and executes terminal window commands to grant or remove permission during testing. The protection engineer supports the microgrid commissioning engineer, validating that the POI relay is operating as intended and the microgrid site can safely and reliably be used on the distribution system. The load

bank operator manages the portable generator and load bank controller to simulate island loading during GFM tests.

B. Test Sequences

Six test sequences are executed in a fixed order. Each sequence targets a specific operating mode and confirms the associated Mirrored Bits handshake, FWTS configuration, and inverter mode transition. For each test sequence, the microgrid commissioning engineer verifies healthy voltage at both the line side and bus side before permissions are issued.

1) Test 1: Offline to Run Mode Enabled and VF/PQ Command Permissions

The initial conditions for this test are as follows:

- FWTS configuration: Parallel
- Microgrid status: Offline
- GFL permission status: Disabled
- GFM permission status: Disabled

The microgrid commissioning engineer confirms the SEC cannot start the microgrid while the permission to run in GFL mode is disabled. The permission to run in GFL mode is then enabled. The microgrid commissioning engineer then confirms the SEC shows the permission is present, the inverter(s) start up in GFL mode, and the SEC sends the status that the microgrid is running in GFL mode to the CPC relay. While the microgrid is running in GFL mode, GFL permission is disabled. The microgrid commissioning engineer confirms the SEC shows the permission is removed, the inverter(s) shut down, and the SEC no longer sends the status that the microgrid is running in GFL

mode to the POI relay, confirming a real-time interlock, not merely a startup gate.

2) *Test 2: Anti-Island Verification*

The initial conditions for this test are as follows:

- FWTS configuration: Parallel
- Microgrid status: Online, GFL
- GFL permission status: Enabled
- GFM permission status: Disabled

The switching of FWPS is coordinated to simulate a live grid loss to the FWTS, the microgrid commissioning engineer confirms the trip of the inverter(s) on undervoltage, and the microgrid transitions to offline and not to GFM mode. This test confirms that an inadvertent island cannot form when GFM permission is disabled. This test is a regulatory interconnection requirement and is documented by the power quality meter.

3) *Test 3: Parallel to Auto-Island*

The initial conditions for this test are the same as those for Test 2.

The permission to auto-island is enabled and Way 4 on the FWTS closes, engaging the grounding bank. The SEC presets the GFM parameters in the PCS while still operating in GFL mode. The switching of FWPS is then coordinated to simulate a live grid loss to the FWTS. When the FWTS senses the loss of grid source on the line side of Way 3, the POI relay trips Way 3 and the SEC transitions the inverter(s) to GFM mode without any impact on the load. The microgrid commissioning engineer confirms the microgrid has transitioned to islanded mode and is sustaining the load simulated by the load banks without grid connection. The microgrid commissioning engineer and the protection engineer analyze the power quality data from the test to verify a smooth transition from GFL to GFM mode at the POI.

4) *Test 4: Parallel to Commanded Island*

The initial conditions for this test are the same as those for Test 2.

The permission for commanded island is enabled and Way 4 on the FWTS closes, engaging the grounding bank. The SEC then modulates inverter output to carry the full downstream load, driving power flow through Way 3 toward zero. Only when zero flow is achieved does the SEC send a request to the POI relay to trip Way 3 open. The POI relay independently confirms zero flow before issuing the trip command to open Way 3, thereby forming the microgrid and separating it from the distribution system. This dual check by both the SEC and the POI relay prevents transfer under non-zero-flow power conditions. Once the POI relay opens Way 3, the SEC transitions the inverter(s) to GFM mode without any impact to the load. The microgrid commissioning engineer confirms the microgrid has transitioned to islanded mode and is sustaining the load simulated by the load banks without grid connection. The microgrid commissioning engineer and the protection engineer analyze the power quality data from the test to verify a smooth transition from GFL to GFM mode at the POI.

5) *Test 5: Island Resynchronization to Grid and Parallel Transition*

The initial conditions for this test are as follows:

- FWTS configuration: Island
- Microgrid status: Online, GFM (commanded or auto)
- GFL permission status: Disabled
- GFM permission status: Enabled

The switching of FWPS is coordinated to restore the grid source to the line side of the open Way 3 position on the FWTS. The permission to resynchronize is enabled, and automation logic within the POI relay begins an internal 60 s timer to ensure the grid source is present and stable for 60 s before resynchronization is allowed. When the timer expires, the resynchronization permission is transmitted from the POI relay to the SEC. The SEC then adjusts the inverter voltage magnitude and frequency to match the grid source. When synchronization is achieved, the SEC sends a request to the POI relay to close Way 3. The POI relay checks the 25A1 synchronism-check element before closing Way 3 and disabling the permission to run in GFM mode and enabling the permission to run in GFL mode. When Way 3 is closed, the microgrid commissioning engineer confirms the SEC transitioned the microgrid into GFL mode. The microgrid commissioning engineer and the protection engineer analyze the power quality data from the test to verify a smooth transition from GFM to GFL mode at the POI.

6) *Test 6: Black-Start-to-Island Transition*

The initial conditions for this test are as follows:

- FWTS configuration:
 - Way 1 closed, Way 2 open, Way 3 open, and Way 4 closed
- Microgrid status: Offline
- Grid source: De-energized line side of open Way 3 on FWTS
- GFL permission status: Disabled
- GFM permission status: Disabled

The microgrid commissioning engineer verifies that the SEC cannot black start without permission and that the microgrid remains offline. The black-start permission is then enabled and automation logic within the POI relay sends black-start and GFM permissions to the SEC. The SEC commands the inverter(s) to transition to GFM mode and energizes the dead bus of the FWTS from the BESS. The SEC then sends the status that the microgrid is running in GFM mode to the POI relay. The POI relay confirms stable voltage and frequency on the FWTS bus before automation logic in the POI relay closes Way 2 on the FWTS, introducing the load from the load banks and simulating the downstream feeder circuits on the distribution system. The microgrid commissioning engineer increases and decreases the load on the load banks in increments to verify the ability of the inverter(s) to sustain load changes in GFM mode without tripping or excessive voltage and frequency deviation. The microgrid commissioning engineer and the protection engineer analyze the power quality data from the operation to identify if any power quality concerns exist.

VIII. SITUATIONAL AWARENESS USING SYNCHROPHASORS

In practical implementations, synchrophasor systems are leveraged to support both real-time operations and engineering analysis through Wide-Area Situational Awareness platforms [5] [6]. Time-synchronized measurements are aggregated into centralized environments where they can be accessed by system operators and engineers for enhanced grid visibility. During commissioning activities, these platforms provide a live visualization of key system parameters—including the breaker status, voltage profiles across interconnected systems, current flows through multiple feeder paths, the power factor, the system frequency, and active and reactive power—enabling engineers to make informed decisions from a safe distance while interacting with energized equipment.

Following commissioning, the same synchronized data streams continue to support long-term operational and planning functions. Engineers use the data for disturbance analysis, fault investigation, system performance trending, and grid planning studies, while system operators leverage the high-resolution, time-aligned measurements to achieve a level of situational awareness that exceeds traditional SCADA or historian-based tools. The ability to observe system conditions with precise temporal alignment across wide geographic areas enables faster detection of abnormal conditions, improved understanding of system dynamics, and more effective operational decision-making.

Overall, synchrophasor measurement systems provide a high-fidelity, time-synchronized representation of power system behavior that bridges the gap between real-time operations and offline engineering analysis. By enabling precise, wide-area visibility of voltage, current, and frequency dynamics, these systems play a critical role in enhancing grid reliability, resilience, and operational efficiency in modern

power networks. Fig. 14 shows the dashboard that the utility uses for DER applications.

IX. CONCLUSION

This paper has presented SDG&E's approach to integrated protection, control, and communications for DER-rich distribution systems, built around a CPC relay and a standardized four-way pad-mounted switch platform. Applying a single protection settings group with mode-supervised logic, rather than switching between settings groups, allowed the same relay to support grid-parallel, islanded, resynchronization, and black-start operation while keeping the settings philosophy consistent and auditable across the growing BESS and microgrid fleet.

The protection philosophy adapts to the fault current available in each mode: conventional overcurrent coordination is retained where area EPS fault contribution is present, while voltage-supervised overcurrent and negative-sequence elements carry protection responsibility once the microgrid is islanded and limited to inverter-based fault contribution. The switchable internal and external ground bank configurations further show how grounding design choices directly determine ground fault detection capability once the system separates from the grid.

The paper also highlights the use of a synchrophasor-based ROCOF element (81RF), which detects an unplanned loss of the utility source using existing PMU functionality in the relay rather than a dedicated frequency-tracking algorithm. Both laboratory validation and a field commissioning event confirmed that the element reliably distinguishes true islanding from faults and normal switching events, with the relay, inverters, and SEC operating in the coordinated sequence that the design intended.

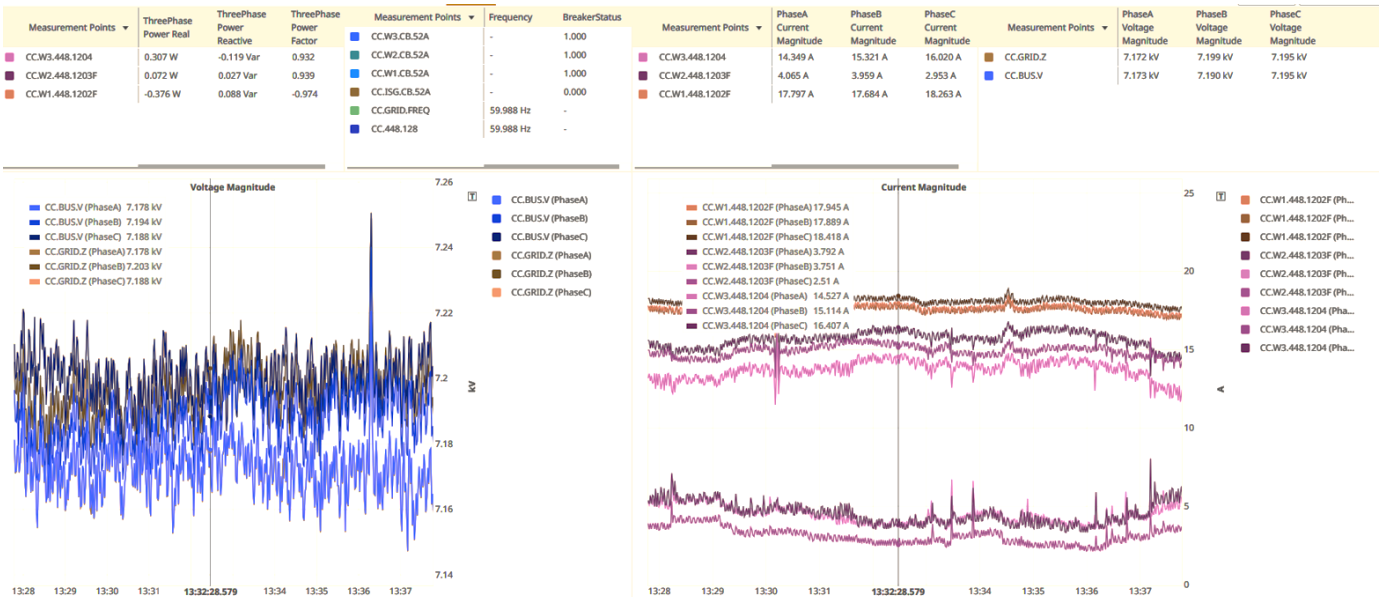


Fig. 14. Wide-Area Situational Awareness Display for DER Applications

Finally, the standardized testing and commissioning framework, anchored by an identical FWTS and a fixed sequence of six test cases, ensures each operating mode is independently validated before being placed in service and continues to support operations, disturbance analysis, and planning long after commissioning. As the utility continues to expand its BESS and microgrid portfolio, this standardized architecture provides a scalable, field-proven foundation, with ongoing field experience informing continued refinement of settings and logic as DER technologies and operating conditions evolve.

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XI. BIOGRAPHIES

Stan Karpenko is a senior relay test engineer at San Diego Gas & Electric (SDG&E), specializing in protection system settings, laboratory-based relay testing, and diagnostic analysis for transmission and substation networks. His expertise includes microprocessor-based protection schemes, centralized protection and control architectures, advanced phasor measurement unit analytics for system dynamics and event reconstruction, and integration of inverter-based resources across both transmission and distribution systems. Stan holds a BS in Electrical Engineering from California Polytechnic State University, San Luis Obispo, and is a licensed professional engineer in California.

Maison Cowley is currently part of the Substation Commissioning Engineering team at San Diego Gas & Electric (SDG&E), where she is training to commission substation equipment and protection schemes in substations ranging from 4 kV to 500 kV across SDG&E's service territory by 2027. In her previous role at SDG&E, she was the lead commissioning engineer for four microgrid projects in the company's Distribute Energy Resources group and designed and implemented the microgrid test bed at SDG&E's integrated testing facility to perform microgrid testing in a laboratory environment prior to field commissioning. Maison holds a Bachelor of Science in Electrical Engineering from California State University, Sacramento, and is a licensed professional engineer in the state of California.

Charlie Cerezo is a senior supervisor of relay test engineering at San Diego Gas & Electric Company (SDG&E). He leads a team responsible for the protection and automation systems that support SDG&E's electric distribution network. Prior to his current role, he served as a system protection and controls engineer and project engineer for SDG&E's Advanced Protection Program (APP), supporting the deployment of advanced protection technologies across electric substations and distribution systems. Charlie holds a Bachelor of Science degree in Electrical Engineering from California State Polytechnic

University, Pomona, is a licensed professional engineer in California, and is an active member of the IEEE 1547.7 Working Group.

Danica Prather is currently a district engineer at San Diego Gas & Electric (SDG&E), where she supports the electric troubleshooters and customers for the Northeast district area. Prior to this role, she worked as a distribution system protection engineer at SDG&E for five years, supporting the development and coordination of settings for the metropolitan area and assisting with the testing and commissioning for multiple microgrid sites. She joined SDG&E in 2020 as part of their Engineering Associate Rotation Program, where she completed rotational assignments in Project Portfolio Management-QAQC, System Protection Maintenance, and System Protection. Danica obtained her bachelor's degree in Electric Engineering in 2020 from California State Polytechnic University, Pomona, and is a registered professional engineer in California.

Adam Manley is currently the SCADA and integration manager at esVolta, where he supports utility-scale battery energy storage systems (BESSs) and projects. Prior to this role, he worked as principal engineer for the Distributed Energy Resources department at San Diego Gas & Electric (SDG&E) for around three years. Adam obtained his bachelor's degree in Computer Science in 2008 from California State University San Marcos and his professional engineer license in Electrical Engineering in 2023 for the state of California. He has twenty years of experience in the electric utility industry, working different roles as a software developer, technical engineer, and electrical engineer responsible for design, implementation, and testing of renewable energy asset controls and communications.

Mohit Sharma is currently part of the Sales and Customer Service division at Schweitzer Engineering Laboratories, Inc. (SEL), where he supports customers, primarily in the Southwest U.S., on the application of protection schemes and systems. Prior to this role, he worked as an application engineer for protective relay test products and solutions in the Engineering division at Megger for around six years. Mohit obtained his bachelor's degree in Electrical Engineering in 2012 from National Institute of Technology, Bhopal, in India and his master's degree in Electric Power Systems Engineering in 2015 from North Carolina State University, Raleigh. He also has two years of coal-fired generation power plant experience in India working with Indiabulls Power, an independent power producer, as an electrical maintenance engineer responsible for the testing and maintenance of low-voltage and medium-voltage switchgear and generator protection panels. He is a registered professional engineer in California and is an active member of the IEEE PSRC committee.

Amanvir Sudan received his bachelor of engineering degree in electrical and electronics engineering in 2011 from Panjab University in India. He then received his Master of Science degree in electrical engineering with a power system emphasis in 2013 from Washington State University in the United States. Amanvir joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2012 as an electrical engineering intern for the Engineering Services division, where his focus was automation. Since January 2014, Amanvir has been working as an application engineer in protection in the Sales and Customer Service division of SEL and supports SEL customers in the Southwest region of the United States.